BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2021-88-E

IN RE:	)
Dominion Energy South Carolina, Incorporated's 2021 Avoided Cost Proceeding Pursuant to S.C. Code Ann. Section 58-41-20(A)	)

PROPOSED ORDER

ON BEHALF OF

DOMINION ENERGY SOUTH CAROLINA, INC.

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INTRODUCTION

This matter comes before the Public Service Commission of South Carolina ("Commission") pursuant to the requirements of S.C. Code Ann. § 58-41-20, which was enacted into law by 2019 Act No. 62 ("Act No. 62") and became effective on May 16, 2019. S.C. Code Ann. § 58-41-20(A) directs the Commission to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements ("PPAs"), commitment to sell forms, and any other terms or conditions necessary to implement this section." S.C. Code Ann. § 58-41-20 further requires the Commission "at least once every twenty-four months . . . approve each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section." Consequently, on March 10, 2021, the Commission established the above-captioned docket for the purpose of establishing Dominion Energy South Carolina, Inc.'s ("DESC" or the "Company") standard offer, avoided cost methodologies, Form PPAs, commitment to sell forms, and any other terms or conditions necessary to implement the requirements of S.C. Code Ann. § 58-41-20.

I. NOTICE AND INTERVENTIONS

By letter dated April 30, 2021, the Clerk's Office of the Commission instructed the Company to publish, by May 11, 2021, a Notice of Filing and Hearing and Prefile Deadlines ("Notice") in newspapers of general circulation in the area affected by the issues presented in this proceeding. Among other things, the Notice informed customers and the public of the nature of the proceeding and advised all interested parties desiring participation in the scheduled proceeding of the manner and time in which to file appropriate pleadings. On May 24, 2021, the Company filed with the Commission affidavits demonstrating that the Notice was duly published by May 11, 2021, in accordance with the instructions set forth in the April 30, 2021 letter.

Timely petitions to intervene were received from Carolinas Clean Energy Business Association ("CCEBA"); Johnson Development Associates, Inc. ("JDA"); Pine Gate Renewables, LLC ("Pine Gate"); the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy (collectively, "CCL/SACE"); and the South Carolina Department of Consumer Affairs ("DCA"). DESC did not oppose the petitions to intervene and no other parties sought to intervene in this proceeding. The South Carolina Office of Regulatory Staff ("ORS") also is a party of record pursuant to S.C. Code Ann. § 58-4-10(B).

II. PREHEARING MATTERS

On March 10, 2021, in Order No. 2021-166, the Commission established prefiled testimony deadlines and hearing dates. In accordance with Order No. 2021-166, DESC filed its Application to Approve and Establish Pursuant to S.C. Code Ann. Section 58-41-20(A) the Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and all Other Appropriate Terms and Conditions on April 22, 2021. DESC stated that it would submit its proposals for each of the S.C. Code Ann. § 58-41-20(A) items as part of the filing process established by Order No. 2021-166.

On May 12, 2021, DCA filed a Motion for Commission to Review the Sufficiency of DESC's Application, contending that DESC should submit its proposals for the S.C. Code Ann. § 58-41-20 items as part of its application instead of doing so as part of the filing process. CCL/SACE filed a letter supporting DCA's Motion on May 18, 2021. DESC filed its Response in Opposition to Intervenor's Motion for Commission to Review the Sufficiency of DESC's Application on May 24, 2021, contending in pertinent part that it was not required by statute or regulation to include its proposals with an application. On May 26, 2021, in Order No. 2021-384, the Commission granted DCA's Motion and directed DESC to file a supplemental application on or before June 7, 2021, to include the "Company's proposals for its standard offer, avoided costs methodologies, form contract power purchase agreements, commitment to sell forms, and any and all other appropriate terms and conditions for which it seeks approval." On June 7, 2021, in compliance with Order No. 2021-384, DESC filed its first Amended Application to Approve and Establish Pursuant to S.C. Code Ann. §58-41-20(A) the Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and all Other Appropriate Terms and Conditions, containing the proposals required by the Order.

On June 25, 2021, DESC filed its Second Amended Application to Approve and Establish Pursuant to S.C. Code Ann. §58-41-20(A) the Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and all Other Appropriate Terms and Conditions, in which it amended certain exhibits as more fully explained in the cover letter filed with the Second Amended Application. On June 29, 2021, in accordance with Order No. 2021-166, DESC prefiled the direct testimony and exhibits of its witnesses.

On July 7, 2021, CCEBA filed a Motion for Extension of Time and for Other Relief ("First Motion for Extension"), seeking certain relief with respect to the timeline established in Order No. 2021-166. In response to the First Motion for Extension, Chief Hearing Officer David Butler issued Order No. 2021-96-H, holding in abeyance the July 13, 2021, testimony filing deadline established by Order No. 2021-166 for ORS and the Intervenors. DESC responded in part to the First Motion for Extension by email to Hearing Officer David Butler on July 13, 2021, disagreeing with the allegations made by CCEBA and stating that it would reply to the Motion, but that it would not "object to a delay of 2 weeks as long as it is not prejudiced by the delay and given a full

2 weeks in which to file its rebuttal testimony." On July 16, 2021, CCEBA filed a Notice of Withdrawal of Motion for Extension of Time and for Other Relief, by which it withdrew the First Motion for Extension, and DESC filed a Notice of Withdrawal of Email Addressed to Hearing Officer David Butler and Dated July 13, 2021. Also on July 16, 2021, CCEBA filed a Consent Motion for Extension of Time and Motion to Continue Hearing ("Consent Motion for Extension"), in which it stated that the "Parties have resolved the issues which gave rise to" the First Motion for Extension. In the Consent Motion for Extension, all Parties agreed to the following relief:

- That the deadline by which Intervenors and ORS must file Direct Testimony is extended until July 27, 2021.

- That the deadline by which DESC must file Rebuttal Testimony is extended until August 10, 2021.

- That, in the event CCEBA's further motion to extend the hearing date set forth below is denied, that the deadline by which Intervenors and ORS must file Surrebuttal Testimony is extended until August 13, 2021.

Also on July 16, 2021, Chief Hearing Officer David Butler issued Order No. 2021-99-H, stating that the Commission would consider the Consent Motion for Extension at its Business Meeting on July 21, 2021. At that meeting, the Commission issued Order No. 2021-504, denying a continuance of the hearing scheduled to begin on August 18, 2021, but extending the testimony filing dates as follows:

- All Other Parties Direct Testimony Due: July 27, 2021
- Rebuttal Testimony Due August 10, 2021
- Surrebuttal Testimony Due August 16, 2021, by 2 p.m.

On July 27, 2021, in accordance with Order No. 2021-504, ORS and the Intervenors[1] prefiled the responsive direct testimony and exhibits of their witnesses. On August 10, 2021, the Company prefiled the rebuttal testimony and exhibits of its witnesses and, on August 16, 2021, the other parties of record prefiled surrebuttal testimony and exhibits of their witnesses.

III. SELECTION OF THIRD-PARTY CONSULTANT AND EXPERT

In accordance with S.C. Code Ann. § 58-41-20(I), the Commission on March 31, 2021, issued Order No. 2021-231, approving the issuance of a Request for Proposal for a Consultant and Expert" for DESC's 2021 Avoided Cost Proceedings. In accordance with Order No. 2021-231, the Commission on April 19, 2021, issued the first Request for Proposal ("First RFP") to provide consulting services with respect to the determination of avoided costs for DESC. This First RFP required offers to be submitted no later than May 3, 2021, at 2 pm. On May 5, 2021, the Commission issued Order No. 2021-319, establishing a schedule with respect to engaging the third-party consultant pursuant to the First RFP. Also on May 5, 2021, pursuant to Order No. 2021-319, the Commission published a Notice of Receipt of Proposal in Response to RFP. However, on May 17, 2021, a Statement of No Award was issued by the State of South Carolina Purchasing Office with respect to the First RFP after the one offeror requested that their offer be withdrawn.

On May 19, 2021, the Commission issued Order No. 2021-363, approving the issuance of a "Request for Proposal for Consultants and Experts" for DESC's 2021 Avoided Cost Proceedings. On this same date, the Commission also issued Order No. 2021-364, approving a marketing strategy that the Commission's Public Information Office presented with respect to the "Request

[1] JDA, Pine Gate, and DCA did not submit prefiled direct or surrebuttal testimony.

for Proposal for Consultants and Experts" for DESC's 2021 Avoided Cost Proceedings. In accordance with Order No. 2021-363, the Commission on June 16, 2021, issued the second Request for Proposal ("Second RFP") to provide consulting services with respect to the determination of avoided costs for DESC. On July 14, 2021, the Commission issued Order No. 2021-488, establishing a schedule with respect to engaging the third-party consultant and expert pursuant to the Second RFP. Also on July 14, 2021, pursuant to Order No. 2021-488, the Commission published a Notice of Receipt of Proposals in Response to RFP, identifying the four entities to submit proposals in response to the Second RFP. DESC on July 19, 2021, in accordance with Order No. 2021-488, submitted proposed questions for the four prospective third-party consultants and experts.

On July 21, 2021, in accordance with the timeline set forth in Order No. 2021-488, the Commission conducted interviews of the four prospective third-party consultants and experts. These prospective third-party consultants and experts filed their Final Written Conflict Check Letter with the Commission on July 23, 2021, as required by Order No. 2021-488. On July 28, 2021, the Commission in its Regular Commission in its Business Meeting voted to select London Economics International, Inc. as its third-party consultant and expert ("Independent Expert") pursuant to S.C. Code Ann. § 58-41-20(I). On July 29, 2021, the Commission issued Order No. 2021-520, establishing the following scope of work and schedules for the Independent Expert:

- Review all filings on the PSC Docket Management System, including all prefiled testimony.
- Verify the avoided cost methodology and calculations included in all Parties' testimony.
- If necessary, file data requests with the Parties.
- Write and file the Consultant's Independent Report.

- The Consultant's Independent Report must be based on the evidence of the hearing record, according to S.C. Code Ann. §58-41-20.
- The Consultant's Independent Report shall serve as its prefiled testimony and exhibits.
- The Consultant's Independent Report must be filed with the Commission at contact@psc.sc.gov – I repeat contact@psc.sc.gov – and served on all parties to the case.
- The Consultant will respond, if necessary, to discovery from parties regarding the Consultant's Independent Report.
- Should the Consultant need to communicate with the Commission and with any party in the case, the Consultant must file such communication at contact@psc.sc.gov **and** will serve all the parties to the case. The expert should not need to talk with the Commission staff unless there are scheduling or procedural issues. And that would be the same if the consultant needs to talk to the Commissioners, I am pretty sure that is going to be for procedural scheduling matters.
- Watch/Observe all the hearing(s) via livestream.
- Also, the Consultant may be required to testify before the Commission regarding the Consultant's Independent Report and subject to cross examination by the parties and questions from the Commission.

In Order No. 2021-520, the Commission also established the following timeline with respect to the Independent Consultant's work:

- The Consultant's Report is due September 16, 2021.
- The Discovery Deadline, including Consultant's Deposition, to be completed by the Parties by October 5, 2021.
- The Consultant's Testimony and Cross Examination followed by Commissioners' Questions is scheduled for October 6, 2021, through October 7, 2021.

Pursuant to Order No. 2021-520, LEI filed its report on September 16, 2021 ("LEI Report"). On October 8, 2021, DESC, CCEBA, and CCL/SACE filed responsive testimony with respect to the LEI Report.

IV. HEARINGS

A. Initial Evidentiary Hearing

In order to hear testimony, receive documentary evidence, and consider the merits of this case, the Commission convened a hearing on this matter on August 18-25, 2021, with the Honorable Justin T. Williams presiding. DESC was represented by K. Chad Burgess, Esquire; Matthew W. Gissendanner, Esquire; Mitchell Willoughby, Esquire; and Tracey C. Green, Esquire. JDA was represented by Weston Adams, III, Esquire and Courtney E. Walsh, Esquire. CCEBA was represented by Richard L. Whitt, Esquire, and John D. Burns, Esquire. CCL/SACE was represented by Kate Lee Mixson, Esquire, and Emma C. Clancy, Esquire. Pine Gate was represented by Richard L. Whitt, Esquire; and J. Blanding Holman, Esquire. DCA was represented by Roger P. Hall, Esquire; Carri Grube Lybarker, Esquire; and Connor J. Parker, Esquire. ORS was represented by Christopher M. Huber, Esquire, and Alexander W. Knowles, Esquire. In this Order, DESC, JDA, CCEBA, CCL/SACE, Pine Gate, DCA, and ORS are collectively referred to as the "Parties" or sometimes individually as a "Party."

DESC presented the direct testimony of Daniel F. Kassis and Eric H. Bell and the direct testimonies and exhibits of Peter David, James W. Neely, John E. Folsom, Jr., and Allen W. Rooks. CCEBA presented the responsive direct testimony of Steven Levitas and the responsive direct testimony and exhibits of Edward Burgess. CCL/SACE presented the responsive direct testimony and exhibits of Kenneth Sercy. ORS presented the responsive direct testimony of O'Neil O. Morgan and the responsive direct testimony and exhibit of Brian Horii. As noted above, JDA, Pine Gate, and DCA presented no direct testimony.

In response to the issues raised in the responsive direct testimony presented by the other parties, DESC presented the rebuttal testimony of Witnesses Bell, David, Kassis, Neely, and

Thomas E. Hanzlik. DESC also presented the rebuttal testimony and exhibits of Witnesses Folsom and Rooks.

CCEBA presented the surrebuttal testimony of Witness Levitas, and the surrebuttal testimony and exhibits of Witness Burgess. CCL/SACE presented the surrebuttal testimony and exhibits of Witness Sercy. ORS presented the surrebuttal testimony of Witness Horii. JDA, Pine Gate, and DCA presented no surrebuttal testimony.

On August 23, 2021, the Commission granted CCEBA's motion, which allowed CCEBA to prefile Supplemental Surrebuttal Testimony and Exhibits of CCEBA Witness Burgess related to the Corrected/Revised Rebuttal Testimony of DESC Witness David. In Order No. 2021-638, the Commission established October 5, 2021, as the date on which Witness Burgess was required to prefile his Supplemental Surrebuttal Testimony. CCEBA filed Witness Burgess's Supplemental Surrebuttal Testimony on October 5, 2021.

B. Hearing for the Consultant's Testimony and Cross Examination and Other Matters.

In order to hear testimony and receive documentary evidence with respect to certain matters left open at the conclusion of the Initial Hearing on August 25, 2021, and the LEI Report, the Commission convened a hearing on October 11-13, 2021, with the Honorable Florence P. Belser presiding. DESC was represented by K. Chad Burgess, Esquire; Matthew W. Gissendanner, Esquire; Mitchell Willoughby, Esquire; and Tracey C. Green, Esquire. JDA was represented by Weston Adams, III, Esquire, and Courtney E. Walsh, Esquire. CCEBA was represented by Richard L. Whitt, Esquire, and John D. Burns, Esquire. CCL/SACE was represented by Emma C. Clancy, Esquire. Pine Gate was represented by Richard L. Whitt, Esquire, and J. Blanding Holman, Esquire. DCA was represented by Roger P. Hall, Esquire, and Connor J. Parker, Esquire. ORS was represented by Christopher M. Huber, Esquire, and Alexander W. Knowles, Esquire. LEI was not represented by counsel in this proceeding.

DESC Witness David was presented for cross-examination by the Parties and the Commission. Afterward, CCEBA presented the supplemental surrebuttal testimony of Witness Burgess. LEI did not submit any prefiled testimony; however, AJ Goulding testified on behalf of LEI regarding the LEI Report, which was introduced as Hearing Exhibit 13, and answered questions from the parties and the Commission. CCEBA presented the responsive testimony and exhibit of Witness Burgess. CCL/SACE presented the responsive testimony of Witness Sercy. DESC presented the responsive testimony of Witnesses Kassis, Folsom, Bell, Neely, and David. JDA, Pine Gate, DCA, and ORS presented no responsive testimony.

V. STATUTORY STANDARDS AND REQUIRED FINDINGS OF FACT[2]

A. Background of PURPA

As discussed below, these proceedings arise from Act No. 62, which is part of South Carolina's implementation of PURPA. PURPA was passed during the oil embargo and natural gas shortage of the 1970s.[3] PURPA was enacted to promote:

- The conservation of electric energy;
- Increased efficiency in the use of facilities and resources by electric utilities;
- Equitable retail rates for electric consumers;
- Expeditious development of hydroelectric potential at existing small dams; and
- Conservation of natural gas while ensuring that rates to natural gas consumers are equitable.

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[2] To the extent the following findings of fact are conclusions of law, they are adopted as such.

[3] As discussed below, PURPA has been reformed several times since its enaction to account for changes in the marketplace and industry as a whole.

In furtherance of these goals, the Federal Energy Regulatory Commission ("FERC") imposed certain obligations upon utilities with respect to generators that obtain "qualifying facility" status (each, a "QF"). Generally speaking, to qualify as a QF under PURPA, the (i) generator has to use a renewable fuel source, such as wind, solar, biomass or the like, and (ii) facility must not exceed 80 megawatts AC ("MW-AC"). Among other things, PURPA contains a mandatory purchase obligation related to the power supplied by these QFs, sometimes referred to as the "the PURPA put" or just "put." As implemented pursuant to the FERC's Order No. 69, utilities are required to purchase power from the QF at rates that do not exceed the utility's avoided cost. This mandatory purchase can be established through sales made (i) on an as-available basis; or (ii) under a long-term agreement, which can take the shape of a (a) long-term power purchase contract, (b) standard offer agreement which has standardized rates and terms for smaller projects up to 100 kilowatts ("kW"), or (c) binding, non-contractual relationship, or legally enforceable obligation ("LEO"), as described below. Although the utility must purchase this power from eligible QFs, the FERC has made clear that such rates must be nondiscriminatory to QFs, while at the same time being just and reasonable to customers to ensure that customers do not subsidize these QFs. Via Order No. 69[4] which implemented PURPA, the FERC imposed two other primary requirements upon utilities. Utilities must:

- Provide QFs with interconnection service;
- Provide backup electric energy to QFs on a non-discriminatory basis and at just and reasonable rates.

[4] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (1980) ("Order No. 69").

Additionally, PURPA also largely exempts QFs from federal and state utility regulation. The FERC regulates rates and services for wholesale sales of electricity and electric transmission in interstate commerce, while states regulate the local distribution of electric energy and retail sales of electric energy to customers or "end users." The sale of energy from an independent generator to a public utility is a wholesale sale and is otherwise subject to FERC regulation. Depending on the size of the plant, PURPA exempts QFs from most of the Federal Power Act and Public Utilities Holding Company Act of 2005. PURPA also exempts QFs from certain state laws and regulations respecting rates as well as financial and organizational aspects of utilities.

B. Recent Federal Reforms of PURPA

As discussed above, PURPA was enacted almost half a century ago during an oil embargo and natural gas shortage. Since then, the energy landscape in this country has changed dramatically, and PURPA has changed in response. Although there have been various federal legislative and regulatory reforms of PURPA since its enactment, the most recent reform efforts were implemented in July of 2020 via Order No. 872 and its progeny. [5] Through Order No. 872 and the following orders, the FERC's reform efforts within Order No. 872 focused on a broad array of topics, including avoided cost caps, the "one-mile rule," and standards to secure a LEO. *Id*.

The FERC stated that these modifications were necessary based on "demonstrated changes in circumstances that took place after the PURPA Regulations were first adopted." Order No. 872 at 20. Although Order No. 872 discussed a wide range of topics, the provisions most relevant to this proceeding relate to avoided costs and compliance with PURPA's requirement that these rates

[5] *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 85 FR 54638 (Sep. 2, 2020), 172 FERC ¶ 61,041 (2020) ("Order No. 872").

must not exceed the utility's actual avoided cost. In this regard, the FERC noted that although PURPA requires utilities to purchase QF generation at avoided cost, evidence reveals that "existing PURPA avoided cost rate provisions are not necessary for some independent power generators to put in place contractual arrangements . . . that are sufficient to obtain financing." Order No. 872 at 242. Likewise, the FERC noted that, historically, it expected that over and under recovery due to inaccurate avoided cost rates would "balance out." However, in issuing Order No. 872, the FERC cited evidence that demonstrates that such balancing does not always occur, and "that on some occasions long-term fixed QF rates were well above actual avoided costs, thereby causing consumers to subsidize those QFs in contravention of PURPA and the [FERC's] expectations." In response, FERC granted specific measures all designed to allow more flexibility to calculate accurate avoided cost rates. These recent reforms evidence a clear concern for protecting the interest of ratepayers, which is a concept echoed in South Carolina's implementation of PURPA via Act No. 62.

C. Background of Act No. 62

Dubbed the "Energy Freedom Act," Act No. 62 addresses a wide range of topics related to renewable energy. Importantly, Act No. 62 encourages the development of renewable energy resources, such as solar generation, in a manner that (i) is fair and balanced, (ii) considers the impacts to all customers arising from renewable energy on the utility's system, and (iii) ensures that revenue recovery, cost allocation, and rate design of utilities is just and reasonable. Relevant to this proceeding, Act No. 62 represents rates, forms, and contracts available to QFs under PURPA. Act No. 62 further establishes procedures to ensure that QFs are properly compensated for the energy they produce, as is required by PURPA, while at the same time mandating that costs not be shifted onto other utility customers resulting in the subsidization of such programs. In this manner, Act No. 62 is designed to ensure that the Company determines its costs and sets its rates at just and reasonable levels and implements the programs required by the act, while also preventing the shifting of costs to customers. As discussed below, S.C. Code Ann. §58-41-20(A) is clear in providing, among other things, that "[a]ny decisions by the [C]ommission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the [FERC's] implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public." This re-iterates the importance of ensuring that the Commission's decisions in this docket adequately protect the Company's customers by mitigating potential risk arising from the Company's purchases from QF generators under PURPA.

D. Requirements of S.C. Code Ann. § 58-41-20

Among other things, Act No. 62 requires the Commission to establish "each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement" the requirements of S.C. Code Ann. § 58-41-20.

1. Avoided Cost Methodology

As defined by both PURPA regulations and Act No. 62, "avoided costs" are "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from [QFs], such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6); S.C. Code Ann. § 58-41-10(2). FERC further recognizes that avoided costs include two components: "energy" and "capacity." Specifically, "[e]nergy costs are the variable costs associated with the production of electric energy (kW-hours). They represent the cost of fuel and some operating and maintenance expenses.[6] Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities." *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg. ¶ 12,214 at 12,216 (Feb. 25, 1980) ("Order No. 69"). The Commission also has recognized in Order No. 81-214, dated March 20, 1981, Docket No. 80-251-E, and in subsequent decisions that electric utilities are entitled to recover from customers their avoided costs paid to QFs under PURPA.

Importantly, PURPA does not require electric utilities to pay QFs more than their avoided costs. To the contrary, PURPA and its implementing regulations expressly provide that "[n]othing . . . requires any electric utility to pay more than the avoided costs for purchases" from QFs. 18 C.F.R. § 292.304(a)(2). Similarly, by setting a ceiling of incremental costs on the amount a utility should be required to pay for a QF's power, Congress expressed that PURPA is "not intended to require the rate payers of a utility to subsidize cogenerators or small power products." H.R. Rep. No. 95–1750, at 98. For these reasons, PURPA is intended to equalize the rates charged for utility power resource additions and utility purchases of QF power so as to make certain that customers do not pay more for electricity under either option.

In like manner, Act No. 62 does not provide or allow the Commission to provide benefits or incentives for solar generating facilities, beyond the payment of the utility's avoided costs as objectively established. To the contrary, S.C. Code Ann. § 58-41-20(A) provides that "[a]ny decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility … and shall strive to reduce the risk placed on the using and consuming public." Thus, if a utility's

[6] The Commission also has recognized that energy costs include certain environmental costs which are subject to recovery in fuel rates pursuant to S.C. Code Ann. § 58-27-865.

avoided costs are calculated reasonably to reflect the utility's avoided costs, customers would not be impacted by purchases of QF power and would be economically indifferent to whether the power in question was supplied by the QF purchase or by other means. Under both PURPA and Act No. 62, utilities are only required to pay QFs the utility's avoided costs, and nothing more. To do otherwise would be in direct contravention of the requirements set forth in S.C. Code Ann. § 58-41-20(A) because it would require customers to improperly subsidize these privately held QF projects, including privately owned solar generating facilities.

In considering the avoided cost methodologies to be approved in this proceeding, S.C. Code Ann. § 58-41-20(B) requires the Commission to "treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that:

> (1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs; . . . and;
>
> (3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. Avoided cost methodologies approved by the commission may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility."

2. Act No. 62 Documents

The Act No. 62 documents are available to QFs that wish to take advantage of DESC's "must purchase" obligation under PURPA. Although these form documents are called for by Act No. 62, they do not represent the sole avenues via which QFs can sell power to DESC under PURPA. Both PURPA and Act No. 62 expressly acknowledge that QFs and DESC can negotiate mutually-agreeable terms and conditions that differ from the Form PPA and Standard Offer contracts approved in this docket. S.C. Code Ann. § 58-41-20(A); 18 C.F.R. § 292.301(b).

Consistent with Act No. 62, any decisions by the Commission related to these documents "shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the [FERC's] implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public." S.C. Code Ann. § 58-41-20(A).

a. Standard Offer

A standard offer (the "Standard Offer") is defined by S.C. Code Ann. § 58-41-10(15) to mean "the avoided cost rates, power purchase agreement,[7] and terms and conditions approved by the commission and applicable to purchases of energy and capacity by electrical utilities … from small power producers up to two megawatts AC in size." Stated differently, a Standard Offer is a PPA that contains an avoided cost rate paid to eligible QFs that are 2 MW in size or smaller. Additionally, the Standard Offer contract sets the terms and conditions and allows any qualifying small power producer, as defined by S.C. Code Ann. § 58-41-10(14), to contract with the utility to supply electricity at established rates without the need to negotiate individual contracts. The Standard Offer therefore establishes set prices, terms, and conditions, and is not negotiated by DESC or the eligible QF. It is intended to address the concern that the costs of negotiating and administering individually-negotiated contracts could render smaller projects non-viable. In this manner, Act No. 62 expands the requirements of PURPA, which only requires that utilities have in place standard rates for QFs up to 100 kW-AC, by increasing the upper limit on the required offer of standardized rates, terms, and conditions contained in PURPA from 100 kW-AC to 2

[7] "'Power purchase agreement' means an agreement between an electrical utility and a small power producer for the purchase and sale of energy, capacity, and ancillary services from the small power producer's qualifying small power production facility." S.C. Code Ann. § 58-41-10(9).

MW-AC in size, a 20-fold increase. An increase of this magnitude in the availability of Standard Offer contracts accentuates the importance of ensuring that their pricing, terms, and conditions do not prejudice the interests of customers.

b. Form Contract PPA

A form contract PPA ("Form PPA") is similar to a Standard Offer, except that, pursuant to S.C. Code Ann. § 58-41-20(A), it is for use for qualifying small power production facilities that are not eligible for the Standard Offer, i.e., QF facilities that are greater than 2 MW and up to 80 MW in size. The statute also requires that these PPAs contain provisions for force majeure, indemnification, choice of venue, confidentiality provisions, and other such terms. However, the PPA is not determinative of the price or duration of the contract. These issues are to be separately negotiated by the Company and the applicable QF and "may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility." S.C. Code Ann. § 58-41-20(B)(3). As proposed by the Company, the terms and conditions for the Standard Offer and the Form PPA are similar since the potential impacts to the Company's system and its customers from projects 2 MW or less in size can be comparable to those that exceed 2 MW.

c. Notice of Commitment to Sell Form

Act No. 62 also mandates that QFs "have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the [PPA] then in effect by delivering an executed notice of commitment to sell form to the electrical utility." S.C. Code Ann. § 58-41-20(D). This standard notice of commitment to sell form ("NOC Form") is required to provide the QF a reasonable period of time from its submittal of the form to execute a PPA, but shall not require a QF, "as a condition of preserving the pricing and terms and conditions established by its submittal of an executed [NOC Form] to the electrical utility, . . . to execute a [PPA] prior to receipt of a final interconnection agreement from the electrical utility.” *Id.*

VI. EVIDENCE OF RECORD AND RESULTING FINDINGS OF FACT[8]

A. DESC’s Recent Experience under PURPA

As discussed above, the renewable energy landscape in the United States has changed dramatically since the enactment of PURPA, as acknowledged by the FERC in its most recent reform efforts. DESC Witness Kassis provided testimony on this topic and described his experience working directly with QFs under PURPA on behalf of DESC. 1 Tr. at 20.6. According to Witness Kassis, DESC “historically received few PURPA projects.” 1 Tr. at 16.2-16.3. The projects it did receive were typically submitted by industrial customers wanting to self-build and sell excess power back to DESC. 1 Tr. at 20.6. However, Witness Kassis cited the existence of the federal tax credits, the passing of Act No. 236 in 2014 and now Act No. 62, as well as the continued downward trends in the cost to construct solar facilities and the tremendous increase in intermittent, solar generation on the DESC system in recent years. 1 Tr. at 20.11. DESC’s experience has shown that PURPA has transformed into a mechanism by which developers can develop utility-scale QFs and force the utility to purchase 100 percent of the output at or below its avoided costs. *Id*. Witness Kassis went on to explain the extent to which this penetration of utility-scale solar QFs has increased on the DESC system in recent years. 1 Tr. at 20.12. In the summer of 2019, the nameplate capacity of “utility-scale solar generation on the DESC system was approximately 498 MW.” 1 Tr. at 20.12. For the summer of 2020, the nameplate capacity of

[8] As to all factual matters, they reflect the Commission’s decision that the preponderance of the evidence as presented in this hearing, and after weighing the probative value and credibility of the testimony of each witness, supports the conclusion reached. To the extent the following findings of fact are conclusions of law, they are adopted as such.

utility-scale solar generation on the DESC system was approximately 863 MW—an approximately 75% increase year-over-year—with utility-scale solar generation capacity alone expected to exceed 1,000 MW in the near future. *Id*. Witness Kassis tallied 3,832 MW of additional planned solar and/or energy storage projects pending in DESC's state and federal queue. *Id*. This means that there is a very real potential that solar QFs on the DESC system could exceed 4,800 MW in the near future. The record reveals that this number would easily surpass DESC's average daily peak load—which is less than 3,300 MW—and would fall just short of DESC's highest recorded daytime system load, which was 4,926 MW on August 10, 2007. *Id*. Although the capacity of "must purchase" solar arising from QFs on the DESC system is poised to approach DESC's highest recorded daytime load, Witness Kassis explained that DESC is unable to "turn off" the influx of these QF solar generators. 1 Tr. at 20.15. That is, PURPA mandates that DESC continue to purchase this generation regardless of need, provided the purchase is at or below DESC's system avoided cost. 1 Tr. at 20.16.

According to Witness Kassis, the impacts of such significant amount of solar QF generation on the DESC system are exacerbated by the realities of PURPA—that is, developers of these QF generators are typically only focused upon meeting financial goals with respect to cost and revenues (utility's avoided cost) of the project. 1 Tr. at 20.15. As such, the Commission understands that in these situations, concerns for customer needs or impact to the DESC system would be limited, if they exist at all. This means that not only must DESC continue to purchase QF power, but DESC has little ability to shape or design the purchase to address a particular need of DESC's customers or DESC's reliability requirements. As discussed below, this can adversely impact the DESC system, even resulting in operational issues and/or curtailment.

Conversely—as explained by Witness Kassis—when DESC adds or purchases generation outside of PURPA, it does so to meet identified customer needs in the most economic and reliable manner. 1 Tr. at 20.15. Likewise, when DESC self-builds or purchases power in the market, it is doing so to address specific needs and negotiates one or more products to best fit those needs. *Id*. On this front, DESC Witness Kassis explained a number of initiatives that DESC is committed to achieving outside the restrictions of PURPA, including decommissioning older plants, reducing carbon emissions, and integrating emerging technologies that present reasonable long-term solutions by providing environmental benefits while also addressing safety and reliability issues. 1 Tr. at 20.13. For example, DESC's parent company, Dominion Energy, Inc., announced last year that it intends to achieve net-zero emissions by 2050. *Id*. Likewise, DESC has received numerous awards recognizing its specific commitment to renewable energy. 1 Tr. at 20.14. Finally, the Dominion Energy Innovation Center houses the Duke Energy eGRID, an electrical grid simulator, and the world's most-advanced wind-turbine drivetrain testing facility. *Id*.

Regardless of PURPA, DESC stated that it will continue these initiatives and plan for and incorporate solar power as well as other renewable resources and emerging technologies—including but not limited to renewable generation, energy storage, together or independently—in accordance with the integrated resource plan ("IRP") process to address customer needs in a reliable and economic manner. *Id*. Given the push to reduce carbon emissions not only in South Carolina, but also across the globe, DESC stated that the focus going forward is not whether there will be renewable resources and emerging technologies, but whether the incorporation of renewable resources and emerging technologies will be done in a way that meets DESC customer needs in the most reliable and economic manner. *Id*.

It is with this background that the Commission must address the issues in this docket put before it via South Carolina's implementation of PURPA under Act No. 62. Importantly, the record reveals that PURPA had the intended effect of adding large amounts of cheaper renewable resources to the DESC system, but at the current, significant penetration levels, PURPA's corollary consumer protections measures are taking effect—including declining avoided cost rates due to addition of similar resources—and those must be given equal weight and effect. As discussed above, the FERC recently acknowledged, QFs no longer must rely upon the avoided cost structure to obtain financing, and the dangers of paying inflated avoided cost rates to needlessly incentivize development is a very real danger that would only detriment DESC's customers. Order No. 872 at P. 21. As such, the Commission must address these issues through the lens of the changing energy landscape in South Carolina, all while accounting for customer interests—as required by Act No. 62 and PURPA.

B. Avoided Cost Methodologies

1. Difference in Revenue Requirements Methodology

DESC proposes to continue using the Difference in Revenue Requirements ("DRR") methodology to calculate both the energy component and the capacity component of its avoided costs. 2 Tr. at 46.6-46.7. The DRR methodology is one of the generally accepted methods for calculating PURPA avoided energy costs, is used throughout the United States, and has been previously approved by the Commission in Order Nos. 2016-297, 2018-322(A), and 2019-847. *Id.* at 46.6; 6 Tr. at 32.11. Witness Neely testified that the DRR method best represents how DESC actually would put value to the system. 2 Tr. at 130. He explained that the peaker method does not capture any of the things that are unique to the DESC's system. 2 Tr. at 130-31.

The DRR approach involves calculating the revenue requirements between a base case and a change case. 2 Tr. at 46.6. The base case is defined by DESC's existing and future fleet of generators and the hourly load profile to be served by these generators, as well as the solar facilities with which DESC has executed PPAs. *Id.* The change case is the same as the base case except that a zero-cost purchase transaction is modeled after assuming the addition of an incremental amount of QF energy to its system. *Id.* For the avoided energy cost determination, DESC uses a carefully constructed computer program called PLEXOS, which models the commitment and dispatch of generating units to serve load hour by hour, makes two runs, and estimates the production costs and benefits that result from the purchase transaction. *Id.* The base and change cases are identical except for the zero-cost purchase transaction and, *Id.* The avoided energy cost is the difference between the base case costs and the change case costs. *Id.*

For avoided capacity costs, DESC also uses the DRR. *Id.* at 46.7. Using either the resource plan in its latest IRP or another resource plan, if more appropriate, DESC calculates the incremental capital investment-related revenue required to support its resource plan. *Id.* For the calculation of avoided capacity costs, DESC derives a change case in its resource plan by considering the impact of adding incremental QF capacity. *Id.* The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan. *Id.*

Although the other parties of record raised concerns with certain inputs and assumptions used in connection with the DRR methodology, which will be addressed further below, no other party proposed an alternative methodology to calculate DESC's avoided costs or objected to the use of the DRR methodology. The Commission therefore finds that it is appropriate for DESC to continue using the DRR methodology to calculate its avoided costs.

2. Incremental Change Amount

As part of the DRR methodology, DESC proposes to calculate its avoided energy and capacity costs based upon an assumed incremental addition of 100 MW of QF energy. 2 Tr. at 46.9. ORS, however, proposes to calculate the avoided capacity costs based upon an assumed addition of 66 MW of QF energy based upon the capacity of combustion turbine ("CT") units that DESC models to use in meeting that capacity change. 6 Tr. at 32.22. ORS Witness Horii stated the mismatch in generator sizes biases the avoided capacity cost downward. *Id.* No other party of record proposed that a different capacity addition should be used in connection with the DRR methodology.

LEI, however, agreed with Witness Horii's position, finding that "the Company is **modeling the impact of a 100 MW capacity change**, while . . . this need is being met by 66 MW generators." Hr'g Ex. 13 (LEI Report) at 31 (emphasis in original). This approach, according to LEI, "underestimates the value of capacity," and thus, "the size of the capacity change and the size of the generator should be set equal to one another to correct this mismatch." *Id.*

DESC Witness Neely testified that using a capacity change of 100 MW is consistent with DESC's calculation of avoided energy costs and that the MW change should reflect the MW change that it would be required to purchase over the next two years. 2 Tr. at 50.3. Witness Neely also noted that PURPA allows using a capacity change of up to 100 MW. *Id.* Witness Horii testified that energy and capacity costs are based on independent models, and that solar profile uses MW impacts that vary hourly, and that PURPA does not require using the same MW change for each model. 6 Tr. at 34.5-34.6.

The Commission finds that it is appropriate for DESC to use a 100 MW change in energy in connection with its DRR methodology. PURPA specifically allows that a utility may use a change of up to 100 MW to calculate avoided costs, 18 C.F.R. § 292.302(b)(1), and Act No. 62 specifies that the Commission's decisions in this proceeding shall be consistent with PURPA and FERC's implementing regulations and orders. S.C. Code Ann. § 58-41-20(A). In addition, the Commission finds that it is reasonable to have the energy and capacity changes reflect this same change and that DESC will be adding solar well in excess of 100 MW. In this way, DESC's change number more closely reflects the amount needed to meet the reserve margin requirement each year. The Commission therefore finds that the use of a 100 MW change in QF capacity is reasonable, appropriate, and consistent with Act No. 62, PURPA, and the FERC's implementing regulations and orders.

3. Avoided Energy Costs – Time Periods

Using the DRR methodology, DESC proposes to calculate its avoided energy costs over two time periods. 2 Tr. at 46.7. The short-run avoided energy costs that are reflected in Rate PR-1 and which apply to small QFs of not more than 100 kW are calculated for the 12-month period May 2021 through April 2022. 2 Tr. at 46.15. For solar QFs that have production capacity up to 2 megawatts ("MW") and that are subject to Rate PR-Standard Offer, and for solar QFs that have production capacity greater than 2 MW and that will sell the energy generated pursuant to an executed PPA, DESC calculates the long-run avoided energy costs for a 10-year period. 2 Tr. at 46.7-46.8. DESC then divides these 10-year periods into two groups of five years. *Id.* For non-solar QFs subject to Rate PR-Standard Offer, DESC follows the same methodology, but then accumulates the avoided energy costs into 11 time-of-production periods reflecting the amounts non-solar QFs would be paid based on how much energy they produce in each of the 11 time-of-production periods. 2 Tr. at 46.8. For Rate PR-1, DESC uses the same methodology but simplifies the calculation to four time-of-production periods. 2 Tr. at 46.14.

CCL/SACE Witness Sercy contended that DESC had not justified its use of the time periods for Rate PR-1 and Rate PR-Standard Offer. 4 Tr. at 60.10. He stated that the information produced by DESC, such as a "heat map," did not support the time-of-production periods determined by the Company. 4 Tr. at 60.11-60.12. However, DESC Witness Bell explained that the heat map was not used to define hours and, instead was a Microsoft Excel feature that illustrates differences in data on a spreadsheet and, further, that the formatting provided by Excel is just a starting point and that the average costs of different groups were derived mathematically. 2 Tr. at 181.17-181.18, 227. In sum, he explained, the heat maps provided a starting point for the development of groups that were adjusted in a logical manner for season and hour of day to create a practical and useable rate schedule. 2 Tr. at 181.18. Witness Sercy responded that the information reflected in the heat map did not support the conclusions drawn by DESC. 4 Tr. at 62.4 to 62.10. But Witness Bell testified that DESC ran the model to determine pricing periods five times to obtain a more reliable number for the time-of-production periods and that the heat map was not used as a tool to evaluate every run or even the average of those runs but was just a representation of an evaluation monthly averages in one of those runs. 2 Tr. at 227.12-228.18. He further explained that the heat map is immaterial to the calculation and just shows the relative magnitude of the numbers in the selected cells. 2 Tr. at 229.16-230.5. That is, the colors used on the heat map do not matter; only the numbers, which reflect system costs, matter for the avoided cost calculations. 3 Tr. at 6.23-6.24.

ORS Witness Horii testified that DESC's time-of-production periods are reasonable. Specifically, he stated that four time-of-production periods are reasonable for Rate PR-1 because the DESC marginal energy costs show only moderate variation by hour of the day within the summer and winter seasons. 6 Tr. at 32.12. He further opined that the 11 time-of-production periods for Rate PR-Standard Offer are reasonable because the higher granularity for the 11 periods will help incentivize generators to export energy in hours of highest value to DESC. 6 Tr. at 32.16. Witness Horii did, however, recommend that, for the four time-of-production periods for Rate PR-1, DESC shift the summer hours of 11:00 a.m. to 2:00 p.m. from summer peak to summer off-peak because this would increase the average summer peak marginal cost and increase the accuracy of the time-of-production averages by 3% over the entire year. 6 Tr. at 32.13-32.14. Witness Bell explained that although DESC believes its determinations with respect to the four time-of-production periods for Rate PR-1 non-solar are reasonable, it does not oppose Witness Horii's recommendation. 2 Tr. at 181.20. LEI agreed that DESC's approach to establishing pricing periods for Standard Offer rates was "data-driven," that the "production periods selected by DESC are a fair fit for the hourly average price outputs," and that "**DESC's pricing periods for Standard Offer rates are sufficient for purposes of this proceeding**." Hr'g Ex. 13 (LEI Report) at 46 (emphasis in original).

CCL/SACE Witness Sercy also asserted that solar producers should be allowed to use DESC's non-solar rates, contending those are in effect technology neutral rates. 4 Tr. at 60.12-60.13. He contended that this would compensate each standalone solar QF more appropriate based on its unique production profile that may vary based on geographic location and choices of technology. 4 Tr. at 60.13-60.14. Because "DESC has experienced more summer peaks in the last decade than winter peaks, assigning all capacity value to winter hours is questionable," according to Witness Sercy. 4 Tr. at 60.28. Concerning avoided capacity costs, Witness Sercy, employing his own analysis, recommended the use of a 52% winter and 48% summer allocation with the winter period covering "6am to 9am during January and February" and summer period covering "2pm to 8pm during June, July and August." 4 Tr. at 60.29-60.30. This analysis is not consistent with actual system peak hour load potential and the drivers of capacity additions on the DESC system. Therefore, payment of the avoided capacity in the 3 morning hours in the months of December, January and February is consistent with system need and the avoided cost methodology.

LEI recommended the "**use of a single avoided capacity rate**" on grounds that "a resource's capability to deliver capacity when required should determine its payment regardless of technology type." Hr'g Ex. 13 (LEI Report) at 36 (emphasis in original). Further, LEI found that a single rate "provides clear price signals, and assures values are assigned appropriately when considering costs avoided from a utility's perspective." *Id.*

Witness Neely, however, disagreed with the notion that the non-solar rates can be applied accurately to a solar profile. 2 Tr. at 80.9-80.14. Witness Bell explained that the reason for the separate rates for solar and non-solar is that solar is limited in dispatchability and flexibility and subject to intermittency and time-of-day restrictions. 2 Tr. at 181.34. Witness Bell further stated that the pricing periods and avoided cost values are aligned with when the energy is most valuable to DESC's system. Witness Bell also noted that the value of solar decreases as more is added to the system because there will be an oversupply in certain low-load conditions due to the fact that solar cannot be reduced or curtailed. 2 Tr. at 181.32-181.33. He stated that the different rates for solar versus non-solar are based on recognizing that the avoided cost rate paid reflects the value on the system. 2 Tr. at 226.10-226.13.

Witness Sercy, however, stated that other elements of DESC's proposal, such as the VIC, accounts for the production of standalone solar and makes the non-solar rate well-suited to solar as well. 4 Tr. at 60.14-60.15. But Witness Neely explained that, because the system dispatch requirements for including solar QFs are more costly than those for non-solar QFs, the avoided cost for solar QFs is less than that of a non-solar QF, which can typically generate around the clock and does not require the constant ramping of other resources. 2 Tr. at 50.11. Witness Neely also explained that, as more solar is added to DESC's system, there are hours in which solar adds power to the system even when it is not needed and those hours are captured in the solar avoided cost. 2 Tr. at 50.11-50.12. He further noted that the large amount of solar relative to total system load causes real issues that will increase in severity as more solar generators with the same or a similar profile are added. 2 Tr. at 50.12. Witness Neely also explained that allowing solar providers to use the non-solar rate would not allow for more accurate compensation to the providers because a lot of the hours included in the non-solar rates are in hours where solar does not generate at all. 2 Tr. at 79.9 -79.22.

Witness Horii testified that using a single solar-specific energy credit for the PR-1 solar energy credit and the Standard Offer solar energy credit solves issues that would arise from time-of-production overcompensation because it specifically estimates the annual value of solar generation through the DRR process and divides that value by the annual solar output. 6 Tr. at 32.14-32.15. He explained that this eliminates the averaging problem that would arise from using time-of-production credits. 6 Tr. at 32.15. He summarized his position by stating that using a single credit for solar producers for Rate PR-1 based on a typical solar output pattern is preferable to an alternative such as the four time-of-production credits. *Id.* He further opined that it is reasonable for the Standard Offer rate for solar generators to not have time-of-production periods since the solar Standard Offer avoided energy cost is specific to the DRR solar QF analysis. 6 Tr. at 32.16.

The Commission finds that DESC's proposed time periods to calculate avoided energy are reasonable and appropriate and that they should be approved for use in this proceeding. The Commission finds that DESC reasonably calculated its time-of-production periods and that none of the parties demonstrated how the data used by DESC did not support its calculations. The Commission further finds that, as recommended by Witness Horii, and accepted by DESC, the summer hours of 11:00 a.m. to 2:00 p.m. should be shifted from summer peak to summer off-peak.

The Commission also finds that DESC reasonably developed solar and non-solar rates for both Rate PR-1 and Rate-Standard Offer and rejects Witness Sercy's contention that solar providers should be allowed to use the non-solar rate. However, the Commission finds no reason to depart from its reasoning in Order No. 2019-847 (Dec. 9, 2019) rejecting a single technology-neutral rate. Here, like there, "the record reflects that stand-alone solar generation has a unique profile that is non-dispatchable and is not similar to other QF resources." (Order No. 2019-857 at 35). Indeed, the Commission finds persuasive Witness Neely's testimony that "[t]he system dispatch requirements for including solar QFs are more costly than those for non-solar QFs" because non-solar resources "can typically generate around the close and do[ ] not require the constant ramping of other resources as is needed with solar QFs." 2 Tr. at 50.11. Separate rates for solar and non-solar QFs reflect the unique operating characteristics of the QF solar resource and the compounding effects of hundreds of megawatts of existing solar already onthe DESC system. Accordingly, the "Commission finds that an accurate avoided cost for incremental, non-dispatchable, stand-alone solar can only be captured using a solar-specific avoided cost calculation." Order No. 2019-847 at 35.[9]

4. Avoided Energy Costs – Natural Gas Pricing Forecasts

CCL/SACE Witness Sercy argued that the Company should have used the U.S. Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") gas price projections like

[9] Because the Commission rejects Witness Sercy's recommendation of using a single rate for solar and non-solar resources, it need not address the proposed revisions to a single rate advanced by Witness Sercy.

it was required to do in Commission Order No. 2020-832, which was issued with respect to DESC's IRP, in order to maintain consistency. 4 Tr. at 60.7 to 60.8. Witness Neely explained that DESC used the best available and most appropriate information and projections in calculating its avoided costs. 2 Tr. at 50.4 to 50.5 He also stated that because the natural gas forecast is one of the more important inputs into calculating avoided costs, DESC was very concerned and very careful about selecting NYMEX gas prices for its forecast. 2 Tr. at 50.4, 52. He explained that Witness Sercy's recommendation would not lead to more accurate gas price projections because the EIA's use of three gas forecasts does not provide a single forecast and instead provides a broad and wide range of how prices might develop depending on numerous factors. 2 Tr. at 50.5. He stated that using the EIA's AEO forecast in this proceeding is not appropriate or required because a prudent and reliable avoided costs calculation requires a more accurate forecast than that provided by any of the three that EIA calculates once a year. *Id.* at 50.5, 52. Witness Neely further explained that DESC's gas price forecast compares very favorably with the AEO forecast and better represents the expected gas prices at the time of the avoided cost calculation because it is created based on current factors, whereas the EIA AEO projections are determined once a year and market conditions may have changed between the time those projections were made and the calculation of DESC's avoided costs. 2 Tr. at 50.6, 52-53. He stated that the NYMEX gas price forecast used by DESC was carefully considered and provides the accurate inputs that DESC needs to accurate calculate avoided costs. 2 Tr. at 53.13-53.19. Witness Neely also testified that the IRP needs three long-term 30-year gas price forecasts, whereas the avoided costs calculation needs only one gas price forecast for ten years. 2 Tr. at 74-75. He also testified that there is a greater need for accuracy in the avoided cost docket due to the nature of the calculations. 2 Tr. at 76.7-76.13.

Witness Horii testified that DESC's changes in fuel price forecasts were consistent with the EIA AEO forecasts. 6 Tr. at 32.17-32.19. Witness Sercy, however, stated that a blended forecast like he recommends is more reliable for calculating avoided costs because it accounts for persistent supply and demand factors and better balances short-term and long-term issues. 4 Tr. at 62.2-62.3. Witness Neely disagreed, stating that the blended forecast would be more accurate in the first year—because it uses the same numbers as DESC used for the first year—but would suffer from the same deficiencies in following years. 2 Tr. at 50.7. Witness Neely, however, testified that the objective of DESC's avoided energy cost calculations is to "derive the most accurate projection that can be ascertained at the time the costs are calculated." 2 Tr. at 50.5. Witness Neely explained that the EIA AEO "does not provide a single forecast" but rather, "a broad and wide range of how prices might develop." *Id*. Thus, according to Witness Neely, while a range of values may be appropriate for an IRP proceeding, "use of th[ese] forecasts is not appropriate or required in this proceeding because . . . avoided costs calculation requires a more accurate forecast," than a once-a-year EIA range of values. *Id*. Witness Neely further explained that although short-term NYMEX prices have changed since the time that DESC performed its calculations, there are less changes in future years and that NYMEX provides the most accurate projection of gas prices. 2 Tr. at 61.16-62.1.

LEI analyzed DESC's approach to establishing its natural gas price outlook and agreed, in part, with DESC and, in part, with Witness Sercy. Specifically, LEI found that for the first three years DESC's use of natural gas futures "represent[s] the best estimate for costs." Hr'g Ex. 13 (LEI Report) at 43. However, "[b]eyond three years," DESC agreed with Witness Sercy that EIA AEO's reference case outlook is preferable for establishing longer-term gas price outlook. *Id*. Each approach, according to LEI, is "equally defensible," but LEI, nevertheless, conceded that "the approach taken by DESC … is in line with approaches taken by LEI in the past to establish longer-term gas price outlooks." *Id*. Thus, LEI concluded that "the price outlook used by DESC" is "within a reasonable range of potential outcomes." *Id*.

The Commission finds that DESC's natural gas price projections are reasonable and appropriate and approves the calculations used by DESC in this proceeding. The Commission finds that DESC acted reasonably in using price projections different from those used in the DESC's IRP proceeding due to the differing nature of the issues between the two proceedings. The Commission further notes that the Company's projections compare reasonably to the EIA AEO projections.

5. Avoided Energy Costs – Operating Reserves

Carrying additional operating reserves for QF solar intermittency is a widely accepted practice and the Company's need to maintain reserves for solar generation was not disputed by the intervening parties. In fact, ORS Witness Horii testified that his consulting firm has observed that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation. 6 Tr. at 32.7. Witness Bell explained that operating reserves to cover unexpected drops in solar output has become a dominant factor only recently due to the level of solar that has been connected to the Company's system. 2 Tr. at 181.6.

CCEBA Witness Burgess stated that the Company's practice of holding 40% of expected solar output in reserve could be appropriate or could be higher than is truly necessary. 5 Tr. at 16.12-16.13. Witness Burgess also stated that the Company has carried operating reserves that exceeded what is necessary. 5 Tr. at 16.14. In response, Witness Bell explained that the Company provide information regarding its historical reserves and that it is a normal outcome of a reliability-constrained, economic unit commitment to have reserves that are higher than the minimum. 2 Tr. at 181.6. Witness Bell further stated that the reserve requirement by its very nature is a minimum requirement and actual reserves will almost always be higher based on the solar forecast, contingency reserve requirements, regulation requirements, and the hourly load forecast. *Id.* He noted that the most constrained hours set the basis for the commitment of firm resources. *Id.* Witness Bell testified that a main factor in determining reserves is economic dispatch, which impacts reserve levels in hours that are not reserve limited. *Id.* Witness Burgess responded that the Company had not justified a need to exceed the 35% of reserves that were assumed as part of the IRP process. 5 Tr. at 31.9. Witness Burgess did not, however, provide any alternative analysis to suggest a lower level of reserves should be assumed by the Company for the avoided cost process, except to say that the levels Guidehouse used in calculating the VIC were too high based on the Company's historic operating practices.[10] *Id.*

The Guidehouse Study modeled incremental operating reserves equal to 60 percent of solar generation to avoid a reserve shortfall. (DESC Response to CCEBA Interrogatory 2-17). Witness Burgess explained that this amount greatly exceeded current DESC practice of keeping operating reserves equal to 40 percent of solar, and that, in any event, monthly average reserve amounts historically carried on the DESC system were more than sufficient to cover present and future solar integration. 5 Tr. at 16.11. Witness Bell testified that the Company was reviewing the Guidehouse recommendations. 2 Tr. at 199. He also testified that the information provided to and used by Guidehouse was accurate and that the 60% modeling was based on assumptions going forward. 2 Tr. at 199-200.

[10] The VIC study and calculation is discussed below. *See* discussion *infra* Part VI.B.9.

The Commission finds that the calculation of operating reserves equal to 40% of solar generation used by the Company in calculating avoided costs is reasonable and necessary to avoid operating reserve shortfall caused by solar intermittency. Indeed, Witness Hanzlik presented graphs depicting real world solar generation on the DESC system over the course of the day from August 12, 2021, through August 17, 2021, showing some drops in solar output well in excess of 60 percent. 2 Tr. at 13, 14. The Commission further finds these charts provided by Witness Hanzlik and submitted as Exhibit 1 show significant decreases in real world solar output during particular hours from August 12, 2021, through August 17, 2021. Hr'g Ex. 1. Moreover, Witness Hanzlik explained that the historical monthly average reserve calculations presented by Witness Burgess were meaningless. 1 Tr. at 206. Specifically, Witness Hanzlik noted that minimum operating reserve requirement is driven by peak hour, and therefore, there may be hours where the system has surplus reserves. 1 Tr. at 207. The Commission notes that Guidehouse recommended establishing operating reserves equivalent to 60%, but the Company is only considering that recommendation and has not yet implemented it. The Commission will again review the level of operating reserves during the next avoided cost proceeding for DESC.

6. Avoided Capacity Costs – Impact of Solar on Capacity Needs

CCL/SACE witness Sercy raised various concerns with certain aspects of the Company's avoided capacity costs. Specifically, Witness Sercy raised the following issues:

1) "QFs should be compensated in such a way that allows for a level of unavailability … Applying a 'performance adjustment factor' ('PAF') within the avoided capacity rate calculations would accomplish this goal." 4 Tr. at 60.18- 60.19.

2) The Company's "avoided capacity cost calculation uses unreasonably low input assumptions, such that the resulting rates do not accurately reflect DESC's avoided costs." 4 Tr. at . 60.32.

3) Solar QFs should be "deemed eligible for the technology-neutral capacity rate coupled with adoption coupled with adoption of [Witness Sercy's] revised, analytically supported technology neutral capacity rate." 4 Tr. at 60.32.

4) The Company's ELCC analysis "cannot be fully evaluated due to use of opaque SAS code, but based on the elements that can be assessed, it does not clear the bar of further advancing the rigor and accuracy of … avoided cost calculations." 4 Tr. at 60.27).

Witness Sercy recommended a 1.05 performance adjustment factor or "PAF" that would increase total avoided capacity costs. 4 Tr. at 60.21. A PAF, according to Witness Sercy, is meant "to allow for a reasonable level of generator unavailability while still providing full compensation for cost recovery purposes." 4 Tr. at 60.19. A PAF is necessary, Witness Sercy posits, "in order to treat QFs on a fair and equal footing with utility-owned resources." 4 Tr. at 60.18.

Witness Neely, asserted, on the other hand, that "[a] PAF artificially inflates capacity values," 2 Tr. at 50.16., because to compensate QFs for periods of unavailability would result in "DESC's customers [paying] for something they did not receive. This would be in direct conflict with the requirements of Act No. 62," which requires rates to accurately reflect a utility's avoided cost. 2 Tr. at 50.15, 94.

LEI agreed with Witness Sercy that "a PAF [should] be included in calculating avoided capacity cost" to "QFs on a more equal footing with utility-owned resources." Hr'g Ex. 13 (LEI Report) at 35. LEI reasoned that the "PAF should not be viewed as an artificial inflation, but an adjustment that leads to a more accurate depiction of the costs for capacity under an understanding that outages consistent with a generic CT is expected." *Id*. Thus, LEI concurred with Witness Sercy's recommendation of a 1.05 PAF. *Id*.

Next, Witness Sercy asserted that the Company's "avoided capacity cost calculation uses unreasonably low input assumptions, such that the resulting rates do not accurately reflect DESC's avoided costs." 4 Tr. at 60.32. Specifically, Witness Sercy takes issue with the Company's capital cost of "991 $/kW capital cost (2020 dollars) for aeroderivative combustion turbine ('aero-CT) technology, and 8.14 $/kW-year fixed O&M cost." 4 Tr. at 60.20. Comparing DESC's figures with "[t]he EIA report on Capital Cost and Performance Characteristics," showing "a capital cost of 1139 $/kW and fixed O&M of 15.79 $/kW," Witness Sercy concluded that the Company's figures as "unreasonably low." *Id.*

Witness Neely disputed Witness Sercy's position that DESC's capital cost and fixed O&M cost input assumptions were unreasonably below. Witness Neely testified that "[t]he aero-CT costs used came from the interactions with turbine vendors and accurately reflect the costs that DESC would have to pay for the turbine being modeled." 2 Tr. at 50.16. "[T]o use a generic cost is not appropriate," according to Witness Neely, "when actual cost data is available." 2 Tr. at 50.16. Moreover, Witness Neely stated that "[m]odeling costs that are higher [than] actual costs would penalize the utility's customers and not accurately reflect the utility's avoided cost." 2 Tr. at 50.16-50.17.

It is LEI's position that because "the **EIA's cost assumptions** for an aero-CT addition are closest to the 100 MW being assessed, they **serve as the best source for avoided capacity cost calculations**." Hr'g Ex. 13 (LEI Report) at 33 (emphasis in original). LEI found that "[w]hen assessing the data submitted by DESC for a 66 MW generator addition against EIA data for aero-CT (which represents 105 MW capacity), costs for the 66 MW generator are higher and would therefore result in higher avoided capacity rates (by around 20%, as compared to using EIA data where avoided capacity rates were higher by 13.9%)." *Id*.

Witness Sercy's recommendation that this Commission adopt a "technology neutral rate" was already addressed in Section VI.B.3 of this Order. As we explained, separate rates for solar and non-solar QFs reflect the unique operating characteristics of each resource and the distinct operating impact each has on the DESC system. Thus, the Commission rejects Witness Sercy's recommendation and finds separate solar and non-solar QF rates to be both necessary and appropriate.

Witness Sercy finally takes issue with the Company's 5% ELCC rate. DESC established solar QF rates by multiplying the annual avoided capacity value of $58.81/kW-year by the ELCC to arrive at an annual avoided capacity value used for solar QFs of $2.9405/KW-year. 2 Tr. at 50.4. Witness Sercy testified that "most of the substance" of the Company's ELCC analysis "is effectively not reviewable, because it is represented in a software program that is not accessible without a license and detail knowledge of the SAS product, rather than being documented openly in a typical report format." 4 Tr. at 60.23. Determining ELCC, according to Witness Sercy, "encompasses a complex set of data inputs and calculations," and if these inputs and calculations are unreasonable, "the ELCC result will be flawed." 4 Tr. at 60.22.

Further, Witness Sercy asserted that DESC's ELCC analysis lacked rigor and failed to adhere to industry standard approaches. 4 Tr. at 60.24. Specifically, Witness Sercy noted that "datasets DESC provided consist of a single year of solar PV generation data, two years of hourly load data spanning months in 2016, 2017, and 2018, and annual forced outage rates for DESC's system generating units." 4 Tr. at 60.24. On the other hand, explained Witness Sercy, "industry standard approaches use complex statistical and probability-based methods, large datasets for a variety of inputs, and simulate thousands of iterations to yield more robust results." 4 Tr. at 60.24.

Witness Neely, however, disputes Witness Sercy's characterization of the underlying data provided for the ELCC calculation as being insufficient to assess the application of the ELCC in this docket, stating that the Company provided "a complete set of data and the SAS program used to calculate the ELCC." 2 Tr. at 50.17. Further, Witness Neely testified on cross-examination that he had specifically asked for stakeholder feedback on the ELCC from intervenors in this docket and received no response. 2 Tr. at 107. Witness Neely also found the 5% ELCC to be "very generous" given that DESC's need for capacity is based on winter peaks. 2 Tr. at 50.19. Witness Neely also testified that the use of 5% in this proceeding instead of the 11.8% from the last proceeding was appropriate because of the additional solar added to the Company's system since that time. 2 Tr. at 109, 114. He testified that 5% is completely appropriate given the level of solar and the type of generators on DESC's system along with the fact that the Company's load is driven by winter peaks, which solar does not help in meeting. 2 Tr. at 111.

Witness Neely further found the Lawrence Berkeley National Laboratory ("LNBL") study, cited by Witness Sercy for the proposition that "DESC's ELCC may be undervaluing solar PV," as unhelpful to analyzing the ELCC results in this docket. Specifically, Witness Neely noted that the LNBL study "is based on solar capacity credits calculated using the load duration method for certain Florida municipal utilities," but that such utilities are completely unanalogous to DESC. 2 Tr. at 50.19, 110. Specifically, he noted that municipal utilities tend to buy generation from outside their system and do not tend to own a lot of generation. 2 Tr. at 110. He also noted that utilities in Florida are different from South Carolina due to the type of customers they have. 2 Tr. at 121. Responding to Witness Sercy's assertions that the Company's ELCC lacked rigor, Witness Neely pointed out that ELCC analysis need not "be complicated in order to effectively calculate the capacity benefit that solar provides to the DESC system" and articulated the Company's three step process. 2 Tr. at 50.18.

LEI did not consider the ELCC in this docket, stating: "As LEI is recommending a technology-neutral avoided capacity rates (i.e., no solar-specific capacity rates), LEI does not view the ELCC issue as relevant, because resources only receive the rate if they generate in the specified periods." Hr'g Ex. 13 (LEI Report) at 36.

After considering the evidence in the record before it on the issue of avoided capacity costs, the Commission adopts the avoided capacity rates proposed by the Company. Avoided capacity rates for non-solar QFs will be set at $0.21781/kWh. Avoided capacity cost for solar QF will be paid out hourly at $0.00140/kWh (as determined by multiplying the annual avoided capacity value of $58.81/kW-year by a 5% ELCC). The Commission finds the Company's proposed avoided capacity rates to be just and reasonable to consumers, consistent with PURPA and FERC regulations and orders, non-discriminatory to QFs, and serve to reduce the risk place on the using and consuming public.

The Commission disagrees with the recommendation proposed by Witness Horii and supported by LEI to match the size of the capacity change and the generator when calculating avoided capacity values. The Company assumed another 100 MW in the change case when it calculated avoided energy costs. The Commission, therefore, finds it appropriate to use 100 MW in the change case when calculating avoided capacity costs. Further, the Commission finds that use of the 100 MW in the change case reasonably reflects the MWs the Company could be expected to be required to purchase from QFs over the next two years.

With regard to the 1.05 PAF recommended by Witness Sercy, the Commission acknowledges that it found a PAF proposed by Duke Energy Carolinas and Duke Energy Progress in Docket Nos. 2019-185-E and 2019-186-E to be "reasonable and supports Act 62's objective of placing QF generators and utility generators on equal footing in terms of reasonable allowance for unplanned outages." Order No. 2019-881(A) (Jan. 2, 2020) at 30. Turning to this proceeding, Witness Sercy argued in favor of a PAF because it will "allow for a reasonable level of generator unavailability while still providing full compensation for cost recovery purposes, which … is how utility-owned generators are treated." 4 Tr. at 60.19.

However, subsequent to the Commission's order in Docket Nos. 2019-185-E and 2019-186-E, the FERC in Order No. 872 (Sep. 2, 2020) further clarified the contours and limits of PURPA. Pertinent here, FERC stated that "***[g]uaranteeing QFs cost recovery is fundamentally inconsistent with PURPA***, which sets the rate the QF is paid at the purchasing electric utility's avoided cost, not at the QF's cost." 85 FR 54638-01, 54646 (emphasis added). In other words, Witness Sercy's underlying reasoning in support of a PAF—that it is necessary "for cost recovery purposes"—is fundamentally inconsistent with PURPA. For this reason alone, the PAF must be rejected. *See* S.C. Code Ann. § 58-41-20(A) ("Any decisions by the commission shall be … consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders"). Further, when pressed on cross-examination, Witness Sercy admitted that the PAF "[b]y definition, [is] not a cost" that DESC incurs, but rather, "relates to the performance of the resources." 4 Tr. at 79-80. Thus, by Witness Sercy's own testimony, a PAF falls outside the definition of a utility's "avoided cost."

Nor should Act 62's "equal footing" language be misconstrued to mean that electric utility and QF resources must be treated equally as Witness Sercy seems to suggest. This is simply not the case. Indeed, FERC also made this point clear in Order No. 872, stating that QFs "***are different from electric utilities***, not being guaranteed a rate of return on their activities generally or on the activities vis a vis the sale of power to the utility and whose risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable." *Id.* at 54681 (emphasis added).

Moreover, the Commission finds that Act 62's "equal footing" language does not contemplate compensating QFs for periods of unavailability. Instead, QFs are "on a fair and equal footing" with electric utilities when "rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs" and "power purchase agreements … are commercially reasonable and consistent with regulations and orders promulgated by the [FERC] implementing PURPA." S.C. Code Ann. §§ 58-41-20(B)(1) and (2).

Accordingly, we agree with Witness Neely that QFs should only be compensated at the full avoided capacity rate if they generate during all avoided capacity payment hours. "Any other way of paying for capacity would cause DESC's customers to pay for something they did not receive." 2 Tr. at 50.15. Therefore, we reject the recommendation of Witness Sercy that a PAF be included in calculating avoided capacity costs. And although LEI supported Witness Sercy's PAF recommendation, it did so without fully analyzing the relevant language in Order No. 872 and S.C. Code Ann. 58-41-20(B). The Commission finds that such language requires excluding a PAF for DESC's system.

We also reject Witness Sercy's recommendation that "DESC be required to use the EIA data points for the aero-CT capital cost and fixed O&M." 4 Tr. at 60.21. Nor does the Commission agree with LEI that "EIA's cost assumptions for an aero-CT addition … serve as the best source for avoided capacity cost calculations." Hr'g Ex. 13 (LEI Report) at 33. Instead, the Commission agrees with Witness Neely that using a "generic cost is not appropriate when actual cost data is available." 2 Tr. at 50.16. This is consistent with the Commission's directive in Order No. 2021-429, issued in Docket No. 2019-226-E regarding the Company's Modified 2020 Integrated Resource Plan, which stated that "[f]uture DESC IRPs should recommend a portfolio of resources that best meet the needs of the DESC system using actual bid data." Witness Neely explained that the prices the Company used are those that it would actually pay for those turbines, and that to use a higher cost would not be accurately calculating avoided costs. 2 Tr. at 102-03. Witness Neely also explained that, although the Commission required the Company to use industry accepted capital cost assumptions from NREL in its IRP, that was due to the fact that the prices used were formed by volume discount. 2 Tr. at 105. In this proceeding, the Company has used prices based on actual bid data, which, he stated, is what the Commission has instructed it to do. 2 Tr. at 105.

Here, the aero-CT is "not based on any kind of volume discount," 2 Tr. at 104, but rather is "based on bid data." 2 Tr. at 105. Witness Neely testified that "those are the prices that [DESC] would actually pay for those turbines, so if we were to use a price higher than the price that [DESC] would pay for a turbine, that would not be accurately calculat[ing] … avoided capacity costs." 2 Tr. at 102. Accordingly, the Commission rejects employing ***generic*** EIA data for aero-CT capital costs and fixed O&M in lieu of ***actual*** cost data provided by the Company.

Finally, the Commission adopts the 5% ELCC advanced by the Company. Although Witness Sercy opposed the ELCC, Witness Horii raised no such concerns with the Company's proposed ELCC. To the contrary, he "agree[d] generally with the Company's methodologies and assumptions" underlying its avoided capacity values. 6 Tr. at 32.21. Moreover, Witness Horii also found the Company's filings and information provided in this docket to be reasonably transparent for an independent review. 6 Tr. at 32.4. Therefore, the Commission finds the 5% ELCC to be an appropriate figure for calculating avoided capacity costs in this docket.

7. Operational Issues Related to Solar

The Commission finds that DESC has demonstrated that the integration of solar energy presents unique operational challenges for a large-scale utility tasked with generating electricity to meet customer demand across its service area during any given day or time. DESC witness Bell explained that solar generation is not tied to customer demand or system dispatching, but rather, the amount of sunlight on solar panels. 2 Tr. at 174.4. That said, factors outside the control of DESC and often unpredictable, such as cloud cover and weather, may significantly influence the amount of solar energy that can be generated at any particular time. *Id*. Consequently, according to Witness Bell, solar electrical generation tends to drop unexpectedly, return unexpectedly, or remain low unexpectedly. 2 Tr. at 174.5. The Commission find that this is in sharp contrast to dispatchable generation, such as that from natural gas-fired generating facilities, which can be controlled and adjusted to produce more or less energy as is needed to meet demand.

Witness Bell illustrated the variable nature of solar output on the DESC system through various charts depicting example production profiles of aggregated output of utility-scale solar generation on certain days in 2020 and 2021. One chart showed that solar generation is inversely related to load on the DESC system during winter days; that is, solar output is minimal or non-existent during early morning and late evening winter peak hours. 2 Tr. at 174.8. This is problematic because, as DESC witness Kassis explained, DESC needs resources that operate when solar is not available on winter mornings and evening peaks. 1 Tr. at 20.16.

Another chart showed a significant drop in solar output during a period when customer demand for energy was increasing on a particular summer afternoon day. 2 Tr. at 174.9. While these charts and others presented by Witness Bell do not quantify DESC's avoided cost, the Commission finds that they illustrate the challenges and limits of solar generation on the DESC system.

Witness Bell explained that solar penetration increased rapidly from 2017 to 2020, resulting in approximately 1003.4 MW of solar generation currently interconnected to the DESC system, with additional solar facilities expected to be introduced into the system in 2022. 2 Tr. at

174.17. With more solar penetration, the Company must be prepared to manage larger unexpected drops in solar output. 2 Tr. at 174.18. This, in turn, will require DESC to carry additional operating reserves. *Id*.

Moreover, Witness Bell explained that dispatchable generation using traditional generation assets is added in order of economic merit as load increases on the system and is removed as load decreases. *Id*. This type of economical dispatch is not possible, however, with solar QF generation because it must be added to the DESC system when generated and generation is not tied to system needs or economic efficiency but to variable weather conditions. *Id*.

DESC witness Kassis echoed Witness Bell, explaining that the Company has had to depart from its economic dispatch model and reduce its generation assets out of economic order to accommodate solar QF energy. 1 Tr. at 20.17. Specifically, for instance, the Company often reduces output of utility-owned assets that have a lower variable cost than solar QF in certain low load hours. *Id*. DESC must also occasionally shut down low-cost flexible generation, creating higher operational costs, to accommodate solar QF power. 1 Tr. at 20.18.

Witness Bell further explained that while improved solar forecasting is helpful to integration efforts, not all forecasted solar generation can be predicted with reasonable certainty. 2 Tr. at 174.19. Consequently, the Company must be prepared for unexpected drops in solar generation well ahead of actual weather contingencies by maintaining sufficient reserve generation to meet system reliability requirements. *Id*. This is critical because, unlike solar QF generators, the Company has an absolute obligation to balance generation to load and maintain reserves at all times. 2 Tr. at 174.20.

Moreover, DESC is subject to reserve requirements established by the North American Electric Reliability Corporation ("NERC") and the Southeast Reliability Corporation ("SERC") and is also a signatory to the Virginia and Carolinas ("VACAR") Reserve Sharing Arrangement. *Id*. The Company's VACAR commitment requires it to maintain required reserve generation capability sufficient to meet a reserve call from a neighboring utility or sudden loss of generation from a generating facility. 2 Tr. at 174.21. Thus, when non-dispatchable solar facilities fail to generate expected electric generation, the burden falls on DESC to ensure sufficient generation is producing power to meet load and that other generation is available to satisfy reserve requirements. *Id*.

Witness Bell testified that the only way to increase available reserve capacity is to construct additional facilities. 2 Tr. at 174.22. He explained that reserves from existing quick start CTs and Saluda Hydro have been fully utilized and no reserve value can be gained from these facilities. 2 *Id.* While the Company could create additional reserves by holding back pumped storage, this tends to add fuel costs because output from higher-cost generation must be increased. *Id*. Further, the Company could operate more coal and gas-fired baseload units, but operation would be under low load conditions or at an uneconomical output level. *Id*.

Solar QF variability also puts additional stress on other generators. Witness Kassis explained that spikes and drops in solar output cause cycling and ramping in other units and that this, in turn, creates thermal and physical stress on responding generators. 1 Tr. at 20.31- 20.32. Consequently, these generators require additional maintenance resulting in further additional costs to the Company. 1 Tr. at 20.32. Moreover, such maintenance may require isolation of assets, resulting in an outage or limited production at certain generational facilities. *Id*.

DESC witness Hanzlik explained the challenges of integrating the inverse relationship between typical solar QF output and winter demand. He noted that winter peaks presented serious operational challenges to system controllers because solar generation is completely out of sync with the winter load profile. 1 Tr. at 189.7. Winter load begins with a morning peak just before sunrise when there is no solar output. *Id*. Thus, solar energy is absent while DESC non-solar generation is near maximum output and while reserves are at the lowest level of the day. *Id*. As the sun rises, load decreases, but solar begins to ramp up and inject power into the system, creating excess generation and high frequency, resulting in compliance issues and increases in inadvertent power flowing out of the DESC balancing authority. 1 Tr. at 189.8.

Witness Hanzlik noted that QF solar does not support peak demand in the Company's balancing authority except for a few summer months, and thus, sufficient dispatchable generation must exist to cover reliability events. 1 Tr. at 189.10. As greater solar penetration has taken place on the DESC system, according to Witness Hanzlik, this has resulted in the need for maintaining increased levels of operating reserves to account for the variability. 1 Tr. at 189.12. This has caused DESC to rely on combined cycle plants to provide more reserve and less base load support, meaning that combined cycle plants cannot provide as much efficient, low-cost energy needs on the system. *Id*. Moreover, Witness Hanzlik testified that DESC must maintain significant operating reserves to account for increased variable solar, regardless of forecasting ability. 1 Tr. at 189.13.

The variable nature of solar output also creates significant challenges with meeting certain reliability requirements. For instance, DESC must comply with the NERC Resource and Demand Balancing ("BAL") Reliability Standards to ensure the reliability of the system. 1 Tr. at 189.6. These standards require, among other things, for DESC to have sufficient operating reserves to respond to fluctuations in frequency and area control area or "ACE." 1 Tr. at 189.7. Sudden drops and spikes in solar, however, can greatly impact frequency and ACE, creating significant compliance challenges for DESC, according to Witness Hanzlik. *Id*. For Witness Hanzlik, the requirement to meet BAL standards and the challenges of solar output variability create a need for significant operating reserves. 1 Tr. at 189.29.

As it concerns DESC's operating reserve requirements, ORS witness Horii testified that his work outside of South Carolina revealed that increasing amounts of solar and wind generation can require additional ramping and reserves to meet the intermittent nature of solar and wind generation. 6 Tr. at 32.7. Witness Horii explained that solar forecast uncertainty is the primary driver for increased incremental operating reserves. 6 Tr. at 32.8. Even Witness Burgess acknowledged that increasing solar penetration into the DESC system will increase the need for operating reserves. 7 Tr. at 34.

Witness Horii noted that DESC's solar forecast study models forecast uncertainty of solar output based upon the difference between a four-hour ahead forecast and actual solar output. 6 Tr. at 32.9. He pointed out that the Guidehouse Study itself recognized that one-hour ahead forecasting would ideally be used for modeling but that this data was not available. *Id.* This is problematic to Witness Horii because a study he cited suggests that solar forecast errors could be reduced by about half when one-hour ahead forecasting schedules are employed. *Id*. This, in turn, could reduce the need for incremental operating reserves.

SACE/CCL witness Sercy took exception with the Company designating the Williams coal plant as "must-run" in its PLEXOS modeling to determine avoided cost rates. 4 Tr. at 60.17. Witness Sercy asserted the dispatch of coal generation is uneconomical and expensive but that utilities have been found to run coal plants even when there are lower cost alternatives. 4 Tr. at 60.16. According to Witness Sercy, dispatching relatively more expensive resources, like the Williams coal plant, in response to solar variability, as opposed to lower cost units, would result in unreasonably low avoided cost rates. 4 Tr. at 60.16-60.17. Thus, Witness Sercy recommended assessing how DESC coal plants are being simulated and whether this inappropriately impacts avoided cost rates. 4 Tr. at 60.17.

Witness Neely, however, testified that the Williams coal plant is designated as must-run because that is how it actually operates. 2 Tr. at 88. To model the Williams coal plan in another way, according to Witness Neely, would be "model[ing] something that's not consistent with the reality." 2 Tr. at 89. He stressed that "we have to model the system consistent with how the system is actually operating" otherwise the modeled results "don't mean anything." *Id.*

CCEBA witness Burgess testified that Witness Hanzlik's testimony revealed that while solar creates new challenges to the DESC system, it is being managed by system operators without any meaningful increase in Company operating costs. 5 Tr. at 31.25. Witness Burgess argued that Witness Hanzlik presented neither evidence of increased operating costs nor evidence that DESC has need to increase total operating reserves. *Id*. Witness Burgess stated, in particular, that the examples provided by Witness Hanzlik in his testimony to illustrate solar variability appear to have been managed events that DESC had more than sufficient operating reserves to meet. 5 Tr. at 31.27-31.28. Moreover, Witness Burgess challenges Witness Hanzlik's assertion that improved solar forecasting will not eliminate the need for operating reserves by explaining that while the need for reserves will not be completely eliminated, it can be substantially reduced through improved forecasting, such as a one-hour ahead forecast. 5 Tr. at 31.29-31.30. Witness Burgess acknowledged, however, that the integration of increasing amounts of solar increases the complexity of Witness Hanzlik's job as system operator due to solar variability. 5 Tr. at 64.

The Commission has reviewed the evidence in the record and is persuaded that the integration of solar into the DESC system results in real additional costs to the Company that, if not captured with an appropriate VIC, will be passed on to ratepayers in contravention of PURPA.

Witness Horii testified that the extensive work completed by his company in California and Hawaii revealed that solar integration can require additional ramping capability and operating reserves. 6 Tr. at 32.7. Witness Horii's out-of-state work is buttressed by the real-world experiences of Witness Hanzlik, who, as a system operator, explained that the addition of solar generation into the DESC balancing authority has resulted in the need to increase levels of operating reserves to account for variability. 1 Tr. at 189.12. Even Witness Burgess admitted that increasing amounts of solar penetration into the DESC system will require additional operating reserves, albeit eventually. 7 Tr. at 34.

8. Proposed Avoided Costs and Methodology

Turning to the calculation of avoided energy cost under the Standard Offer, the Company employed the DRR methodology described above. The change case for non-solar QFs was derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. 2 Tr. at 46.8. The Company then accumulated the annual avoided costs into 11 time-of-production periods by using a profile created using the ten-year average hourly marginal costs. *Id*. Avoided energy costs under the Standard Offer were calculated for calendar years 2022 through 2031 with this period divided into two groups of five years each, 2022-2026 and 2027-2031, for each of the 11 time-of-production periods. *Id*. Witness Neely explained that the change case for solar QFs was calculated by subtracting from the base case a 100 MW power purchase modeled after a solar profile with avoided energy cost calculated in the same ten-year period divided into the same five-year periods as recited above. *Id*.

To calculate avoided capacity cost under the Standard Offer, Witness Neely testified that the DRR methodology for both solar and non-solar QFs was used to determine the incremental capital investment related revenue needed to support the appropriate resource plan using a change case that considers the impact of a purchase from a 100 MW facility. *Id*. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan. *Id*. Witness Neely explained that this method is reasonable because it identifies the adjustments to the utility's expansion plan that are attributable to purchases from QFs and accurately reflects the capacity cost benefits that would result from the QF purchase. *Id.* at 46.9.

For non-solar QFs that qualify for the Standard Offer Rate, Witness Neely testified that the avoided capacity cost is $58.81/kW-year. *Id*. at 46.9 and 50.3. These avoided capacity rates will be paid during the months of December, January, and February for energy generated from 6 a.m. to 9 a.m. 2 Tr. at 46.9. The annual value to be paid for each of the 270 hours during this three-month period, according to Witness Neely, is $0.21781/kWh. 2 Tr. at 46.10 and 50.4.

Witness Neely testified that the avoided capacity cost for solar QFs subject to the Standard Offer Rate is $2.9405/kW-year. *Id.* at 46.10 and 50.4. He explained that this figure was calculated by finding that incremental solar QFs above the existing 973 MW of existing PPAs have a 5% Effective Load Carrying Capacity ("ELCC") rate, and 5% of $58.81/kW-year is $2.9405/kW-year. *Id.* at 46.10 and 50.4. The Company will pay this capacity value hourly as $0.00140/kWh. *Id.*

Witness Neely explained that the ELCC rate employed by the Company in this proceeding changed from the 11.8% ELCC described in Order No. 2020-244. 2 Tr. at 46.10. He noted that "the updated calculation includes all the 973 MW of existing solar PPAs" and that the next 100 MW increment above 973 MW has an ELCC of 5% because "effective load carrying capacity of incremental solar decreases as more solar is added to the system." 2 Tr. at 46.10.

Witness Neely therefore testified that the following avoided costs should be approved for the Standard Offer Rate, 2 Tr. at 46.12–46.13, 50.3-50.4:

STANDARD OFFER RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

$/kWH by 5 Year Period	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11
	Dec, Jan, Feb				Mar, Apr, Oct, Nov				May- Sep		
	5am-9am	9am-5pm	5pm-11 pm	11pm-5am	5am-9am	9am-5pm	5pm-11pm	11pm-5am	11am-5pm	5pm-11pm	11pm-11am
2022-2026	0.03245	0.02599	0.03143	0.02801	0.02995	0.02580	0.03224	0.02693	0.02870	0.03260	0.02599
2027-2031	0.03651	0.02923	0.03535	0.03151	0.03369	0.02902	0.03627	0.03028	0.03228	0.03667	0.02923

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December, January, February 6 am to 9 am	0.21781

STANDARD OFFER RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

$/kWH by 5 Year period	All Hours
2022-2026	0.02695
2027-2031	0.02937

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Solar QFs ($/kWh)

Time Period	**($/kWh)**
All solar generating hours	$0.00140

Witness Neely also testified that avoided cost rates would be available for solar with battery storage. 2 Tr. at 46.13. He explained that this is because the storage would allow moving the generation to different times and, thus, the profile of solar with storage would be very different than other solar. 2 Tr. at 145. Specifically, the Company will provide solar with storage with four cost options. The first cost option is the Rate PR-Storage approved by this Commission in Order No. 2020-552 issued in Docket No. 2019-393-E. 2 Tr. at 46.13. This tariff is applicable to batter storage units greater than or equal to 5 MW and no greater than 25% of the power production capacity of the associated renewable energy generator. 2 Tr. at 46.13. Witness Neely explained that the second and third options are for smaller projects with storage that total 2 MW or less that will be eligible for the non-solar energy avoided cost rate and non-solar capacity avoided cost for Rate PR-Standard Offer or Rate PR-1. 2 Tr. at 46.13. The fourth option permits any solar with storage above 2 MW to negotiate a PPA" using the Rate PR-Form PPA. 2 Tr. at 46.14.

For avoided energy cost calculation under Rate PR-1, Witness Neely testified that for non-solar QFs, the Company uses PLEXOS to estimate the change in production costs that result from serving the base case load and the change case, which is derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. 2 Tr. at 46.14. Witness Neely explained that a non-solar QFs would receive an energy payment based on how much energy they produce in four time of production periods plus a capacity payment determined by the energy produced in certain winter capacity periods. 2 Tr. at 46.14.

Avoided energy costs for solar QFs under Rate PR-1 are calculated the same way the Company calculated the Standard Offer Rate for solar QFs with the only difference being the time period over which the avoided energy costs are estimated. 2 Tr. at 46.14-46.15. Specifically, Witness Neely explained that the short-run avoided energy costs in the PR-1 Rate are calculated for the period of May 2021 through April 2021 whereas the Standard Offer Rate is a ten-year calculation. 2 Tr. at 46.15.

As far as the avoided capacity component for the PR-1 Rate, Witness Neely testified that the same methodology used to calculate Standard Offer avoided capacity costs was used to calculate avoided capacity costs for solar and non-solar QFs under the PR–1 Rate. 2 Tr. at 46.15. This resulted in an avoided capacity cost of $58.81/kWh for non-solar QFs qualifying for the PR-1 Rate to be paid during the months of December, January, and February for energy generated from

6 a.m. to 9 a.m. 2 Tr. at 46.15 and 50.3. For solar QFs, the Company calculated an avoided capacity cost for the PR – 1 Rate of $2.9405/kW-year. *Id*. at 46.15 and 50.4. Incremental solar QFs above the existing 973 MW of existing PPAs, Witness Neely testified, have a 5% ELCC, resulting in the $2.9405/kW-year figure. *Id*.

Witness Neely also explained that the Company proposed changes to the Rate PR-1 time periods for non-solar QFs to reflect the significant changes to the demands and dispatching needs of the DESC system. 2 Tr. at 46.16. In sum, DESC's proposed Rate PR-1 avoided cost rates are as follows:

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Non-Solar	P1	P2	P3	P4
	Non-Summer: Jan, Feb, Mar, Apr, Oct, Nov, and Dec		**Summer: May-Sep**	
$/kWH	5am-9am, 5pm-11pm	9am-5pm, 11pm-5am	2pm-11pm	11pm-2pm
May 2021 - April 2022	0.03435	0.02889	0.03338	0.02830

PR-1 RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	**($/kWh)**
December, January, February 6 am to 9 am	0.21781

PR-1 RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	**Year Round ($/kWh)**
May 2021-April 2022	0.02820

PR-1 RATE: AVOIDED CAPACITY COST
Solar QFs ($/kWh)

Time Period	($/kWh)
All solar generating hours	$0.00140

Witness Neely further noted that the Standard Offer and PR-1 rates will only apply to QFs with a size of 2 MW or less. 2 Tr. at 46.18. For larger QFs, Witness Neely explained, the Company will negotiate PPAs consistent with Act No. 62. Witness Neely testified that the methodology employed by the Company for Standard Offer and Rate PR-1 will be used to calculate the avoided capacity and energy costs under PPAs. *Id*.

SACE/CCL witness Sercy raised three issues regarding the Company's proposed avoided capacity costs:

1) Company calculations related to generating facility availability violate the Energy Freedom Act of 2019 ("EFA") and PURPA's nondiscriminatory standard. 4 Tr. at 60.18.

2) The capital cost assumptions used in DESC's calculation are unreasonable. 4 Tr. at 60.18.

3) The capacity accreditation and allocation approaches DESC proposes are flawed. 4 Tr. at 60.18.

Regarding generator availability, Witness Sercy explained that under the Company's approach to calculating avoided capacity payments, "QFs would only be compensated at the full avoided capacity rate if they generate during all avoided capacity payment hours." 4 Tr. at 60.18. This position is objectionable to Witness Sercy because the same "is not true of utility owned resources." *Id*. Witness Sercy explained that "[a]ll technologies are subject to forced outages," and thus, to "treat QFs on a fair and equal footing with utility-owned resources," compensation should be calculated in "a way that allows for a level of [QF] unavailability." 4 Tr. at 60.18-60.19.

To this end, Witness Sercy recommended the inclusion of a performance adjustment factor or "PAF" when calculating avoided capacity rates "to allow for a reasonable level of generator unavailability while still providing full compensation for cost recovery purposes, which is how utility-owned generators are treated." 4 Tr. at 60.19. Moreover, LEI agreed with Witness Sercy that "a PAF [should] be included in calculating avoided capacity cost" to "QFs on a more equal footing with utility-owned resources." Hr'g Ex. 13 (LEI Report) at 35.

For reasons this Commission has discussed under Section VI.B.6 of this Order, we disagree with the inclusion of a PAF. As we explained, Witness Sercy's underlying reasoning in support of a PAF—"providing full compensation for cost recovery purposes"—is at odds with the FERC's position that "[g]uaranteeing QFs cost recovery is fundamentally inconsistent with PURPA." 85 FR 54638-01, 54646. Witness Sercy's explanation that a PAF is not an actual cost incurred by a utility is also at odds with the definition of an "avoided cost." 4 Tr. at 79-80. Nor do we believe, as we also explained, that placing QFs on an "equal footing" with utility-owned resources necessarily means a requirement for "equal treatment," as Witness Sercy seems to insinuate. Hereto, the FERC made clear that QFs "***are different from electric utilities***, not being guaranteed a rate of return on their activities … and whose risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable." 85 FR at 54681 (emphasis added).

Witness Sercy also found the capital cost assumptions used by DESC in its avoided capacity cost calculations to be unreasonably low. 4 Tr. at 60.20. Specifically, Witness Sercy found that "DESC's capital cost and fixed O&M designation for aero-CT technology was materially lower" than figures recited in an "EIA report on Capital Cost and Performance Characteristics, prepared by engineering firm Sargent & Lundy." *Id.* As a consequence, Witness Sercy believes that Company calculations may fail to accurately reflect avoided capacity costs. *Id*. LEI, likewise, agreed with Witness Sercy finding that because "the **EIA's cost assumptions** for an aero-CT addition are closest to the 100 MW being assessed, they **serve as the best source for avoided capacity cost calculations**." Hr'g Ex. 13 (LEI Report) at 33 (emphasis in original).

The Commission already addressed the issue of capital cost inputs used in DESC's calculation of avoided capacity costs in Section VI.B.6 of this Order. Witness Neely testified that the Company's capital cost assumptions for aero-CT units reflect "the prices that [DESC] would actually pay for those turbines, so if [the Company] were to use a price higher than the price that [the Company] would pay for a turbine" that would not accurately calculate avoided capacity cost. 2 Tr. at 104. The Commission agrees. To put it another way, the Commission is not convinced that using ***generic*** cost data in lieu of ***actual*** cost data results in a more accurate avoided capacity cost calculation. Accordingly, the Commission rejects Witness Sercy's recommendation that the Company be "required to use the EIA data points for the aero-CT capital cost and fixed O&M." 4 Tr. at 60.21.

Finally, Witness Sercy disagreed with the Company's capacity accreditation and allocation approach. Witness Sercy explained that "[c]apacity allocation is the process by which generating technologies are assigned a capacity credit relative to their nameplate capacity." 4 Tr. at 60.22. DESC "uses an effective load carrying capability ('ELCC') methodology for capacity accreditation purposes," according to Witness Sercy. *Id*. ELCC calculation is based on a set of complex data input that if unreasonable will produce a flawed result. *Id*. Witness Sercy testified that DESC failed to provide sufficient information to analyze its ELCC calculation, but that based on the information that was available there was a concern about "lack of rigor" and "failure to incorporate current best practices." 4 Tr. at 60.23.

The Commission previously addressed Witness Sercy's stated concerns related to the Company's ELCC analysis in Section VI.B.6 of this Order. Nevertheless, it is worth repeating that Witness Horii also examined the Company's avoided capacity cost calculations and raised no such concerns related to ELCC. Instead, Witness Horii "agree[d] generally with the Company's methodologies and assumptions" underlying its avoided capacity values. 6 Tr. at 32.21. Nor did Witness Horii complain that he lacked sufficient information from the Company to conduct an independent review of its avoided cost calculations. 6 Tr. at 32.4. Thus, the Commission restates its finding that the 5% ELCC is an appropriate figure for calculating avoided capacity costs in this docket.

Turning next to the Company's avoided energy cost calculations, Witness Horii reiterated that the DRR method employed by DESC "is one of the generally accepted methods for calculating PURPA avoided energy costs" and that the methodology is the same "used by DESC in Docket No. 2019-184-E and approved by the Commission in Order No. 2019-847." 6 Tr. at 32.11. Witness Horii only recommended to refine the four time of use ("TOU") periods proposed by DESC for non-solar generators on the PR-1 Rate, 6 Tr. at 32.12., otherwise ORS recommended that the Commission approve DESC's proposed avoided energy costs for PR-1 for solar, Standard Offer for solar, and Standard Offer for non-solar. 6 Tr. at 32.19.

With regard to the TOU periods for non-solar generators on the PR-1 Rate, Witness Horii acknowledged that DESC proposal in this proceeding is an improvement over current TOU periods, but, nevertheless, found that "a more focused peak period … would provide even greater incentives for generators to provide power when it is most valuable to DESC and retail customers." 6 Tr. at 32.13. According to Witness Horii, "[a] review of DESC's 2022 hour energy marginal costs shows that the average summer marginal costs between 11:00 am and 2:00 pm are significantly lower than the average costs for other peak hours." *Id*. Thus, Witness Horii recommended "the Company shift the summer hours of 11:00 am to 2pm from the summer peak period to the summer off-peak period." 6 Tr. at 32.14.

ORS recommended the following energy credits based on Witness Horii's modified TOU periods for non-solar generators on the PR-1 Rate 6 Tr. at 32.20:

Non-Summer: Jan-Mar & Oct-Dec		**Summer: May-Sep**	
5am-9am, 5pm-11pm	9am-5pm, 11pm-5am	2pm-11pm	11pm-2pm
0.03437	0.02805	0.03608	0.02875

Notably, while the Company believes its "calculations regarding the four PR-1 non-solar time periods are reasonable and prudent," it nevertheless, "[did] not oppose Witness Horii's recommendations." 1 Tr. at 181.20.

Pertinent to this discussion, Witness Sercy also raised the following concerns with DESC's avoided energy calculations:

1) The Company used an unreasonable load forecast that "contribut[es] to an underestimation of the costs associated with qualifying facilities ('QF') such as independent solar facilities." 4 Tr. at 60.6.

2) It is uncertain whether "the proposed pricing periods are just, reasonable, and nondiscriminatory as required by state and federal law." *Id.*

3) "[R]estricting standalone solar QFs to the solar QF rate would not 'treat small power producers on a fair and equal footing with electrical-owned resources'" and the Commission already instructed DESC "to make standalone solar QFs eligible for a technology-neutral rate." 4 Tr. at 60.14.

Witness Sercy takes issue with the Company's load forecast. Specifically, Witness Sercy testified that he "compared the load forecast DESC used in its production cost modeling with the base case load forecast from DESC's Modified 2020 IRP … and found that on average, the megawatt-hour sales forecast used to calculate avoided energy costs was 1.2% below the Modified IRP forecast, and the peak demand forecast was 2% below the Modified IRP forecast." 4 Tr. at 60.9. Witness Neely countered, however, that "the load forecast used in the Company's avoided costs calculations is the Company's latest forecast and comes directly from the 2020 Modified IRP … as required by Order No. 2020-832." 2 Tr. at 50.8.

Neither LEI nor Witness Horii raised any concerns with regard to the Company's load forecast. And Witness Sercy, in his later surrebuttal testimony responding to Witness Neely, acknowledged that the Company had merely included its demand-side management ("DSM") savings into the load forecast, and recommended that DESC include DSM savings in future filings that modify the gross load forecast. 4 Tr. at 62.4. Accordingly, the Commission finds the Company's load forecast used in its avoided cost calculations to be reasonable.

The Commission addressed the matter of pricing periods in Section VI.B.3 of this Order. For the reasons stated therein, the Commission finds that the pricing periods proposed by the Company are appropriate and reasonable.

As it did in the prior proceeding, the Commission finds that solar generation imposes unique challenges and costs to the DESC system that are not shared by non-solar QF facilities. Indeed, Witness Neely testified that the "large amount of solar relative to the total system load causes real issues" that will only "increase in severity as more solar generators with the same or a similar profile are added." 2 Tr. at 50.12. The Commission does not find any reason developed in this proceeding to depart from its reasoning in Order No. 2019-847 rejecting a single rate. Accordingly for these reasons and those set forth in Section VI.B.3 of this Order, the Commission rejects Witness Sercy's recommendation that solar QFs be eligible for non-solar QF avoided cost rates. Notably, Witness Sercy did not provide any calculations or recommended avoided energy costs figures in this proceeding, even though he admitted on cross-examination that he was able to calculate avoided energy costs. 4 Tr. at 100. Instead, Witness Sercy's testimony was limited to critiques of the Company's calculations and figures. Witness Horii, on the other hand, did calculate avoided energy costs, and as recited above, largely recommended adoption of the Company's proposed avoided energy rates, subject to refining proposed TOU periods. The Commission finds that this further bolsters its decision to reject Witness Sercy's recommendations insofar as avoided energy costs.

9. Variable Integration Costs

The variable integration cost (or "VIC") is the cost incurred by the Company to integrate intermittent solar generation into the system. As more intermittent solar is added to the DESC system, the amount of unpredictable generation increases, requiring additional operating reserve and ramping capability. 6 Tr. at 32.7. The increased costs associated with carrying more operating reserve to meet unexpected changes in intermittent solar generation, 3 Tr. at 59.6, as well as other associated costs, 6 Tr. at 32.7, represent the integration costs to the Company. The Commission has previously found support for the imposition of integration charges on QFs. Order No. 2020-244 at p. 4 (Mar. 24, 2020).

Presently, there are 973 megawatts of solar generation projects on the DESC system. Hr'g Ex. 3 (PBD-2) at 6. From this total, 633 megawatts have power purchase agreements with DESC containing a VIC charge clause whereas 340 megawatts do not include such a clause in their respective contracts. 3 Tr. at 55. With respect to future solar QFs that seek to provide DESC with energy under Rate PR-1, Rate PR-Standard Offer, or Rate PR-Form PPA, the Company employed Guidehouse, Inc. to complete an independent study to determine appropriate VIC rates (the

"Guidehouse Study"). 3 Tr. at 59.4; Hr'g Ex. 3 (PBD-2). The study employed operational data provided by DESC to Guidehouse. 2 Tr. at 174.23.

The Guidehouse Study examined the cost to integrate intermittent solar generation under a baseline scenario and three different scenarios of solar integration into the DESC system. 3 Tr. at 54-55, 59.4, Hr'g Ex. 3 PBD-2. DESC Witness David testified that the "baseline scenario includes all of the interconnected solar generation with PPAs that do not include any [VIC] clauses, totaling 340 megawatts." 3 Tr. at 55. The "Tranche 1" scenario includes all baseline solar generation plus 632 megawatts of power purchase agreements with QFs that contain a VIC clause. *Id*. The "Tranche 2" scenario accounts for 100 megawatts of additional solar penetration on top of the Tranche 1 and baseline scenarios. *Id*. And the "Tranche 3" scenario accounts for 300 more megawatts of solar penetration in addition to Tranche 2, Tranche 1, and the baseline scenario. *Id*.

Witness David further testified that "[a]s solar penetration increases, the levelized cost of maintaining additional operating reserves will increase … due to having to operating the system in an increasingly less efficient manner." 3 Tr. at 57. DESC Witness Kassis further elaborated on reduced operational efficiency, testifying that "[s]ometimes, as a result of the QF power, DESC must shut down low-cost flexible generation, which creates higher operating costs." 1 Tr. at 20.17-20.18.

The Guidehouse Study "forecast[ed] the amount of load-following reserves needed with increasing renewable penetration based on the National Renewable Energy Laboratory's (NREL) Solar Integration Data Sets." Hr'g Ex. 3 (PBD-2) at 6. Forecast error under this approach was "simulated based on historical operation of the assumed resources including the impacts of regional weather and geographic diversity." *Id*. The study then calculated the incremental megawatt reserves required by month across all solar Tranches. *Id.* at Table 1.

The Guidehouse Study employed PROMOD, a production cost modeling tool, to analyze system impacts and calculate total production costs with and without (i.e., use of the reserve requirement of the previous Tranche) the additional reserves required to account for increased solar penetration. *Id.* at 7. "The difference of the system costs of the two PROMOD runs were then compared to calculate the cost of integrating solar." *Id.* at 25. The Guidehouse Study concluded that the "levelized VIC over the forecast period between 2022 to 2031" was $1.8016 MWh for Tranche 1 (341 to 973 megawatts), $3.4301 MWh for Tranche 2 (974 to 1073 megawatts), and $4.6345 MWh for Trance 3 (1074 to 1373 megawatts). *Id.* at 8.

ORS Witness Horii agreed with Witness David that the integration of renewable generation creates additional costs for utilities. 6 Tr. at 32.7. Indeed, Witness Horii testified that his firm, Energy and Environmental Economics, Inc. ("E3"), in its extensive work in California and Hawaii found "that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation." *Id*. Further, Witness Horii found "the overall concepts of the calculation methodology used in the Guidehouse Variable Integration Study to be reasonable." 6 Tr. at 32.8.

Nevertheless, Witness Horii advised this Commission not to adopt the VIC charges proposed by the Company finding that "Guidehouse ha[d] not justified their forecast of incremental operating reserve needed to accommodate forecast uncertainty." 6 Tr. at 32.8. Specifically, Witness Horii observed that the Guidehouse Study "models solar output based on the differences between 4-hour ahead schedules and actual solar output" and noting that the study itself recognized that "ideally 1-hour ahead schedules" should have been used. 6 Tr. at 32.9.

Witness Horii testified that "a 2015 study suggests that solar forecast errors could be reduced by about half if 1-hour ahead schedules are used." *Id*. This impacts VIC, according to Witness Horii, because "[a] more accurate 1-hour ahead forecast would reduce unexpected variation of solar generation and thereby reduce the costs of solar integration." 6 Tr. at 34.5. Witness Horii, therefore, recommended that VIC remain at $0.96/MWh subject to true-up pending the results of an independent comprehensive study. 6 Tr. at 32.9.

Similarly, LEI found that given the "extent of contrary evidence introduced regarding the VIC analysis," a "truly independent study" is required. Hr'g Ex. 13 (LEI Report) at 54. Therefore, LEI "concur[ed] with the recommendation proposed by Witness Horii." *Id.* at 55. However, DESC witness Hanzlik disagreed with Witness Horii that employment of a one-hour ahead schedule would substantially reduce "the need for operating reserve," and thus, VIC costs, because DESC must still respond to solar variability "in real time." 1 Tr. at 186. Likewise, DESC Witness Bell also testified that one-hour ahead schedule will not meaningfully reduce VIC because "[r]ecent forecasting may increase accuracy in the short term, but does not create additional firm capability that is needed to maintain reserve." 2 Tr. at 177. Witness Bell further explained that the one-hour forecast does not help because the Company usually does not have a one-hour unit available to provide increased reserves and, thus, the Company has to react before the one-hour forecast is issued. 2 Tr. at 222.

While disagreeing with the position that improved solar forecasting schedules will not reduce VIC, 6 Tr. at 34.5, Witness Horii did concede that Witness Hanzlik and Witness Bell were both in "an excellent position to know how [the DESC] system operates" and "didn't see any intentional effort to mislead" in their respective testimonies. 6 Tr. at 88. Further, Witness Horii found that Witness Hanzlik would be "intimately familiar with how important reserves are" given his experience operating the DESC system. 6 Tr. at 89-90.

Notwithstanding the concerns raised in his testimony, Witness Horii recommended to this Commission that if it was the intent of this Commission to adopt a new VIC rate in this docket (as opposed to commissioning another VIC study at some point in the future), then he would recommend the Commission adopt the $1.80 MW/hr. proposed by the Company for Tranche 1 solar integration. 6 Tr. at 97. Witness Horii testified that "the 1.89 [sic] number of Dominion is kind of in the same ballpark as what's out there for [Duke Energy Progress]. And it's also fairly close, although lower, than what I had previously proposed" in Docket No. 2019-184-E. 6 Tr. at 97.

CCEBA Witness Burgess offered various criticisms of the Guidehouse Study. Specifically, Witness Burgess raised the following concerns about the study:

1) "Historical levels of operating reserves maintained by DESC have far exceeded levels of reserves DESC assumes are required to integrate solar." 5 Tr. at 16.2.

2) "DESC inexplicitly assumed that incremental reserves equal to <u>60%</u> of solar generation are needed to avoid a reserve shortfall." 5 Tr. at 16.19.

3) DESC's use of a 4-hour solar forecast for its VIC analysis as opposed to a 1-hour forecast. 5 Tr. at 16.25.

4) "[M]odeled integration costs should be weighted based on the hourly solar generation profile." 5 Tr. at 16.21.

5) "DESC unfairly assigned 100% of costs associated with the 340 MW of Baseline facilities to the 633 MW of Tranche 1 facilities. This violates the principle of cost causation." 5 Tr. at 16.23.

6) "DESC made the arbitrary decision to restrict operations of the Fairfield pumped hydro facility" that "inflates the instances of shortfalls in the baseline scenario." 5 Tr. at 16.20.

Witness Burgess introduced Table 1 showing monthly average operating reserves into his testimony which he asserted shows that "the typical amount of operating reserves DESC has historically carried on its system … far exceeds what DESC claims is necessary to integrate solar Tranches 1, 3, and 3." 5 Tr. at 16.14. From this, he concluded that "the incremental integration cost to be essentially zero most of the time." *Id.* at 16.15.

Witness Hanzlik, however, testified that historical average reserve numbers are meaningless to the operation of the DESC system. 1 Tr. at 206. A "pile of reserves" could exist on some days in a particular month, he stated, "but it could be one day where it's zero." *Id*. Instead, Witness Hanzlik testified that the Company "look[s] at reserves across the peak hour of the day … [DESC's] minimum reserve requirement is based on that peak hour." *Id.* at 207. Witness Burgess acknowledged that "those monthly values do not provide precise insight into what a system operator must deal with on a minute-by-minute basis." 5 Tr. at 24-25.

Although Witness Burgess characterized as "inexplicable" an operating reserve in the amount of 60 percent of solar generation to avoid reserve shortfall, Witness Hanzlik offered graphs depicting solar output variability from August 12, 2021, through August 17, 2021, showing drops in solar generation of up to 76 percent. 2 Tr. at 13; Hr'g Ex. 1. DESC Witness Kassis similarly testified to "unplanned drops in [solar] generation that exceed 75% of their nameplate ratings." 1 Tr. at 20.19. Regardless, Witness David testified that "Guidehouse did not attempt to match the operating reserve requirement to a specific level of solar capacity or generation" and that the disputed 60 percent figure was "not used in any calculations to determine VIC." 3 Tr. at 67.13.

Like Witness Horii, Witness Burgess raised concerns about the use of four-hour ahead schedules in the Guidehouse Study as opposed to one-hour ahead schedules. However, as discussed above, Witness Hanzlik and Witness Bell, both of whom are intimately familiar with the DESC operating system, assert that the use of a one-hour ahead schedule, even if it improves forecast accuracy, will not impact the Company's need for additional operating reserves to deal with increased solar penetration into the system, which drives VIC cost.

Witness Burgess testified that Guidehouse Study weighted solar generation hours equally but that this fails to "account for the fact that the total MW at risk from a drop in solar output is not equal throughout the day, or throughout the year." 5 Tr. at 16.22. Applying an appropriate hourly weighting "can help ensure that incremental costs are not excessively inflated during times of expected low solar production," according to Witness Burgess. *Id*. Witness David considered applying hourly weighting in the Guidehouse Study, however, he ultimately concluded that "unweighted average better reflected the costs to the system." 3 Tr. at 67.18.

Witness David reasoned that in non-peak solar hours changes in operating costs are "not actually driven by the need to hold additional operating reserves in those specific hours, but rather by macrolevel system generation changes to ensure that you have that level of operating reserves available during those peak solar hours." 3 Tr. at 87. Thus, weighting by hourly solar generation, according to Witness David, "would be applying [an] inappropriate reduction to any sort of production cost changes in those low solar hours." *Id*.

Witness Burgess testified that DESC should have considered certain intra-hour dispatch improvements, such as a regional imbalance market like the contemplated Southeast Energy Exchange Market ("SEEM"). 5 Tr. at 16.17. However, Witness Bell explained that SEEM does not assist in mitigating the VIC because it provides non-firm resources and purchases of those resources therefore will not increase reserves or assist in maintaining reliable and predictable contingency reserves. 1 Tr. at 181.10. Witness Bell explained that the Company will realize savings from SEEM through incremental costs differences between regulating assets on the DESC system and those that can be purchase from other systems in 15-minute increments. *Id*. Witness

Goulding testified that SEEM does not yet exist, is still under consideration at the FERC, and it currently does not consist of many of the features of an organized RTM market. 7 Tr. at 57. Witness David testified that SEEM is currently too speculative to include in the VIC analysis. 3 Tr. at 67.29.

Witness Burgess testified that the Guidehouse Study unfairly assigned 100% of costs associated with the baseline scenario to the 633 MW of Tranche 1 facilities. 5 Tr. at 16.23. Witness David testified, on the other hand, that "the incremental increase in operating reserves calculated for this scenario were based on increasing solar penetration by 633 MW (i.e., the size of tranche 1)" such that "all of the incremental increases in system costs, are attributable specifically to the Tranche 1 solar capacity." 3 Tr. at 67.21-67.22.

Witness Burgess also testified that DESC's decision to "restrict the operations of the Fairfield pumped hydro" was arbitrary and inflated instances of shortfall on the baseline scenario. 5 Tr. at 16.20. However, Witness David countered that there is "no merit to the claim that [Guidehouse's] analysis restricts Fairfield's ability to provide operating reserves." 3 Tr. at 67.16. The PROMOD tool, according to Witness David, "can turn [the Fairfield facility] on immediately in order to provide operating reserves … when it is economic to do so." *Id.*

After considering the testimony of Witness David, Witness Horii, Witness Burgess, other witnesses testifying on matters related to VIC, the LEI Report, and other evidence in the record, the Commission finds that the VIC rates proposed by DESC in the Guidehouse Study to be just and reasonable to consumers, consistent with PURPA and FERC regulations and orders, non-discriminatory to QFs, and serve to reduce the risk place on the using and consuming public. The Commission further finds that there was no basis for using the proposed SEEM to mitigate any of the VIC costs and the fact that it provides non-firm resources that do not assist in establishing firm reserves for providing safe and reliability electric service. The Commission, therefore, adopts those VIC rates proposed by DESC in this docket.

Increasing solar penetration into the DESC system requires additional generation reserves to meet the challenges of integrating solar facilities, resulting in additional costs to the Company that if not accounted through an appropriate VIC will be passed on to the ratepayer. Indeed, even Witness Burgess acknowledged that the growth of solar generation in the DESC system comes at a cost to the Company. 7 Tr. at 34. Importantly, DESC is the ***only*** party to this proceeding to complete a full study analyzing and proposing VIC rates for adoption by this Commission in this docket. Witness Burgess admitted that he did not complete his "own production cost modeling," but rather merely proposed certain changes to the modeling completed by Guidehouse to reach his recommendation on VIC. 7 Tr. at 27.

But LEI Witness Goulding cautioned about the shortcomings of this approach, testifying that while he and Witness Burgess "can engage in a solid peer review … it is important that modeling be performed with an internally consistent set of assumptions." 7 Tr. at 84. Absent performing your own modeling, Witness Goulding warned that "you have to be careful about going in [to another party's model] and pulling various levers and coming up with different number without fulling examining the impact on all the other assumptions that go into the modeling." *Id.*

The challenge with Witness Burgess failing to complete an actual VIC study was revealed when Commissioner Caston questioned him about when additional operating reserves may be needed if they are not required at this time, as Witness Burgess suggested. However, Witness Burgess could not answer the questions, but rather merely responded, "I think – it's hard to put a precise number on it, but I think it's probably, you know, at least a few years out…." 7 Tr. at 36. To which Commissioner Caston responded, "[t]hen to really know … would not a more detailed model need to be performed….?" 7 Tr. at 37. To which Witness Burgess responded in the affirmative. The Commission finds this type of uncertainty on the part of Witness Burgess from the lack of completing a full VIC study to be problematic.

In any event, although Witness Horii raised certain concerns about the Guidehouse Study, he found the study's overall methodology to be reasonable. Nor did his concerns appear to be too great. Indeed, Witness Horii was willing to recommend adoption of the DESC-proposed VIC rate for Tranche 1 if the Commission is intent on adopting new rates in this proceeding. The Commission further finds that various concerns raised by Witness Burgess and other witnesses relating to the Guidehouse Study and proposed VIC rates were reasonably addressed by Witness David and other Company witnesses.

LEI reached a similar conclusion to that of Witness Horii, stating that "if the Commission believes that it must set a fixed VIC as part of this proceeding, LEI concurs with Witness Horii that DESC's proposed VIC for Tranche 1 of $1.80/MWh may be a reasonable value." Hr'g Ex. 13 (LEI Report) at 56. Indeed, Witness Goulding, while under cross-examination, doubled down on this position, testifying that that "LEI believed and continues to believe that if the Commission is unable to continue with an interim VIC of 96 cents, that the ***$1.80 falls within the range of reasonable potential outcomes***. 7 Tr. at 79 (emphasis added). Thus, the analysis of the independent consultant did not detect concerns that were so great with the Guidehouse Study that it would prevent LEI from recommending to this Commission adoption of the study's proposed VIC rates if the Commission is committed to setting a fixed VIC in this proceeding.

Moreover, the Commission finds persuasive the testimony provided by both Witness Hanzlik and Witness Bell relating to the challenges of integrating increasing solar penetration into the DESC system. Both Witness Hanzlik and Witness Bell, due to their long, first-hand involvement with operating the DESC system, were uniquely positioned to provide this Commission with real-world observations and insights (beyond theoretical models, however, sophisticated) into maintaining sufficient operating reserves to meet these challenges.

The Commission further finds that an interim VIC and the prospect of a true-up creates nothing but uncertainty and risk for all stakeholders. Indeed, CCEBA Witness Levitas testified that this Commission's interim VIC "has created considerable uncertainty and difficulty for QFs" such that "new QFs have faced considerable uncertainty about the economics of their projects" making it more difficult to "secure project financing." 5 Tr. at 216.18.

A VIC study has been completed for this proceeding. Performing an additional VIC study may take "nine months to a year" to complete, according to Witness Horii, 6 Tr. at 97, but given the diverging positions of the various stakeholders, the Commission reasonably suspects it will take far longer. In any event, the Commission has little confidence that such an effort and expenditure of time and resources will produce any meaningful new revelations or consensus among the parties and intervenors in this docket.

An interim VIC subject to true-up has been in place for about two years and the Commission sees no compelling reason to elongate (potentially by a year or more) this period further. DESC has proposed VIC rates in this docket that both Witness Horii and the Commission's independent consultant, LEI, have recommended for adoption should this Commission be committed to setting a VIC in this proceeding. The Commission is so committed. Accordingly, the Commission, for the reasons set forth herein, adopts the VIC rate proposed by DESC for Tranche 1 solar of $1.8016/MWh.

The Commission acknowledges that Witness Kassis testified that the Company would accept Witness Horii's proposal that VIC remain at $0.96/MWh on an interim basis, subject to true up, pending the results of another integration study. However, as stated above, the Commission does not believe another VIC study will resolve the differences between the parties, both ORS's expert witness, Witness Horii, and the third-party consultant, LEI, were willing to recommend adoption of Guidehouse's Tranche 1 VIC rate (if the Commission was inclined to adopt a VIC in this proceeding), and delaying adoption of a set VIC rate by another year (or more) will only discourage solar QF development.

That said, the Commission directs DESC to calculate true-up based on the Commission's adoption of a $1.8016/MWh VIC rate. The Company shall file the calculated true-up amount with the Commission within 30 days after receipt of this Order.

C. Form Contracts

DESC proposes minor modifications to its Form PPA and Standard Offer, along with revisions to the NOC Form that primarily aim to accommodate a wide range of projects and implement certain consumer protection measures.

1. Form PPA and Standard Offer

DESC Witness Folsom presented DESC's proposed modifications to the Form PPA and Standard Offer, which he described as "minor changes, which primarily consist of clean-ups that were discovered by DESC in the ordinary course of business." 3 Tr. at 190.19. He explained that the Form PPA and Standard Offer are "very similar . . . and largely based upon the form of PPA that DESC has been using for years for similar utility-scale projects." 3 Tr. at 190.19. Witness Folsom stated that providing similar consumer protection measures for documents intended for both larger and smaller projects is necessary given the wide range and number of QFs that could sell power under the Standard Offer—which Witness Folsom describes as a "unilaterally executed PPA, complete with pricing, terms, and conditions, and available for all eligible QFs up to 2

MW-AC." 3 Tr. at 190.17. DESC Witness Folsom explained that although the Standard Offer is available for projects ranging from 100 kW-AC to 2 MW-AC, the time and resources that would typically go into negotiating contracts for projects falling within this range could vary substantially. *Id*. As such, the Form PPA and Standard Offer are almost identical, which ensures that the same consumer protections utilized when contracting with larger projects in the Form PPA are also utilized for the wide range of projects under the Standard Offer. 3 Tr. at 190.18. This approach has worked well for DESC and permitted the substantial expansion of QF solar in recent years on the DESC system. 3 Tr. at 190.18-190.19. As such, DESC Witness Folsom explained that DESC is proposing identical changes to the Standard Offer and Form PPA in this docket, which include the following:

a. Cash Collateral.

DESC proposes to remove the express right under the Standard Offer and Form PPA for QFs to provide "Cash Collateral" as a form of "Performance Assurance." 3 Tr. at 190.19. DESC Witness Folsom explained the concept of "Performance Assurance" in this context and stated that its primary purpose is to "provide additional cost-protection to customers because DESC can draw down upon such Performance Assurance in the event a QF is unable to fulfill its obligations under the Form PPA or Standard Offer." 3 Tr. at 190.20. Witness Folsom pointed out that although this express option to provide cash would be removed, QFs would still be able to select among a number of other options, including a letter of credit, a parental guarantee, and a surety bond. *Id*. Witness Folsom noted that accepting cash collateral is also problematic from an administrative perspective given that Dominion Energy, Inc. does not accept cash deposits of this nature. *Id*.

CCEBA Witness Levitas acknowledged Witness Folsom's testimony regarding consumer protections, and noted that "the utility is acting typically with respect to ratepayer interests with respect to these matters." 5 Tr. at 236.16-236.18. He also similarly characterized Performance Assurance as a consumer protection measure, noting that these "measures provide protection to ratepayers in the event of QF non-performance under the PPA." 5 Tr. at 216.8. However, Witness Levitas argued that removal of the cash collateral option, in conjunction with proposing a "totally unworkable" surety bond in this docket, is problematic and that the express cash collateral option should be maintained. 5 Tr. at 216.8.[11] In response, DESC Witness Folsom emphasized the fact that no currently-effective PPAs utilized this option, and that although the express reference to cash collateral is removed, the Form PPA and Standard Offer still permit the QF to provide any other form of assurance, so long as it is reasonably acceptable to DESC. 3 Tr. at 197.3. Witness Folsom noted that DESC did not believe this would be a problematic issue for developers—particularly given that no currently-effective PPA utilizes this option. *Id*. However, Witness Folsom explained that DESC is willing to compromise and maintain the express reference to cash collateral in the PPA given that the parties could utilize cash collateral, regardless of whether it is expressly referenced. 3 Tr. at 197.3-197.4. CCEBA Witness Levitas noted agreement and appreciation for DESC's willingness to compromise on this point. 5 Tr. at 218.5.

The Commission finds that maintaining the current language in the Form PPA that expressly references Cash Collateral is appropriate given that the parties reached a compromise reflecting the same and that the Commission previously approved this language in the Form PPA and Standard Offer. Although the Commission will address the surety bond later in this order, the Commission notes that even if the reference to Cash Collateral were removed, QFs may present any number of performance assurance mechanisms to DESC, including a letter of credit, surety

[11] The As discussed below, the Commission notes that LEI reviewed the proposed form surety bond, and explained that it would be no more difficult to obtain in the marketplace than the current form.

bond, or parental guarantee. As noted by DESC Witness Folsom, even if these express references were removed, DESC provides QFs with an avenue to provide whatever form of cash collateral they choose, so long as the parties can reach agreement on the same. However, the entire purpose of performance assurance under these contracts is to mitigate the risk to DESC's customers in the event a QF does not fulfill its contractual obligations. Any performance assurance—whether expressly referenced in the contract documents or not—should be evaluated under these criteria. Through this lens, the Commission finds that cash collateral achieves the threshold level of customer protection and finds it reasonable to maintain the reference in the contract documents in accordance with the parties' agreement on this matter.

b. Environmental Provisions.

DESC Witness Folsom discussed several changes to the Form PPA and Standard Offer to clarify the scope of coverage and to highlight environmental considerations at issue in these documents. 3 Tr. at 192.20.[12] No party expressed disagreement with these proposed changes.

Although these changes are unopposed, the Commission must necessarily ensure that these changes—whether opposed or otherwise—strike a reasonable balance in protecting DESC's customers on one hand and permitting project development on the other. Here, the Commission finds that these changes achieve this balance. The record reveals that QF development is becoming more costly and more complex, and as these projects become more sophisticated, so too do the technologies they employ. For example, energy storage systems are clearly gaining prominence across the country, and DESC has already contracted for 18 MW under its Storage Tariff. These storage systems can utilize a variety of chemicals that are simply not present in traditional solar

[12] These revisions provide coverage for issues related to potential contamination associated with the site and set the stage for emerging technologies.

generators. Likewise, it is reasonable to assume that as more sites utilize emerging technologies, the construction footprint of these projects will necessarily increase, increasing the potential for environmental issues. As such, the Commission finds it reasonable to update the Form PPA and Standard Offer to address these relevant environmental concerns and reflect concepts commonly found in relevant federal and state statutes and case law. In the end, these revisions serve to mitigate the risk upon DESC's customers by properly allocating responsibility for potential environmental concerns arising from these increasingly sophisticated projects.

c. Shortfall Report.

DESC Witness Folsom explained certain revisions to Section 3.5. 3 Tr. at 190.21. As it stands, Section 3.5 requires QFs to pay liquidated damages to DESC if the QF does not deliver to DESC at least 85% of the amount of energy that the parties agree upon at the time of contracting. *Id*. DESC Witness Kassis cites certain operating issues of these QFs that can contribute to this shortfall. 1 Tr. at 20.32-20.33. Regardless of the reason, Witness Kassis described that in the event a project experiences a shortfall, DESC still has to provide power to its customers by going to the market to procure replacement power, which may not represent the most economical option for DESC's customers. *Id*. The changes proposed by Witness Folsom would maintain these damages and require any QF experiencing a Shortfall (as defined in the Form PPA and Standard Offer) during any Contract Year (as defined in the Form PPA and Standard Offer) to submit a report to DESC and the ORS detailing the cause of such Shortfall and how it plans to avoid similar Shortfalls going forward. 3 Tr. at 190.21. DESC Witness Kassis explained that requiring the report to be submitted to the ORS is appropriate because "its mission is centered upon the 'using and consuming public'—the same customers which the shortfall provision seeks to protect." 3 Tr. at 190.22. No party expressed disagreement with these proposed changes.

Although these changes are unopposed, the Commission must necessarily ensure that these changes—whether opposed or otherwise—strike a reasonable balance in protecting DESC's customers on one hand and permitting project development on the other. The Commission finds that DESC's proposed changes strike the required balance in protecting DESC's customers on one hand and permitting project development on the other. It is undisputed that these QFs freely contract for these terms and agree to supply DESC with a certain amount of energy. DESC must necessarily account for this agreed-upon amount of power in planning its system. Likewise, the Commission finds meaningful that the even if a QF falls short of its guaranteed supply to DESC, the Shortfall Report is only required if the QF falls below the 85% threshold—a 15% buffer in favor of the QF. If a QF generator does not supply the agreed-upon amount of power to DESC, DESC must generate or procure power through other avenues—which may prove more costly for DESC's customers. Therefore, it is reasonable to require the QF to analyze the events leading to such shortfall and remedy the same—something that these QFs should likely be doing regardless of any requirement in the PPA. The Commission also finds it reasonable for these reports to be submitted to the ORS given that the ORS may require DESC to submit similar reports from time to time, and these operating issues affect DESC's customers and likely increase the costs borne by the same. Therefore, the Commission approves these changes, as proposed by DESC.

d. System Disruption Notice.

DESC Witness Folsom explained that the proposed revisions to Section 5.1(a) of the Form PPA and Standard Offer were driven primarily by system safety and reliability. 3 Tr. at 190.22. Under the proposed revisions, if a QF's facility creates "recurring power quality issues or other issues that disrupt normal operation" of DESC's transmission or distribution system, then upon notice from DESC, the QF would have a period of eight (8) months to address and remediate such issues. 3 Tr. at 190.22. Witness Kassis cited this experience, in part, as justification for the modifications to Section 5.1(a) of the Form PPA and Standard Offer to ensure that risks to customers arising from these operating issues are mitigated. 1 Tr. at 20.37. DESC Witness Folsom noted that although the documents do not prescribe the actual remediation measures to be taken in the event of such operating issues, the documents do mandate all such remediation be done in accordance with "Good Utility Practice," as defined in the Form PPA and Standard Offer. 3 Tr. at 190.22.[13] No party expressed disagreement with these proposed changes.

Although these changes are unopposed, the Commission must necessarily ensure that these changes—whether opposed or otherwise—strike a reasonable balance in protecting DESC's customers on one hand and permitting project development on the other. The Commission finds that DESC's proposed changes are in line with the suite of consumer protection measures presented by DESC in this proceeding. As such, these changes are reasonable and serve to protect DESC's customers without prohibiting project development. The record and this order contain evidence proving that these performance issues, including power quality issues, present challenges to DESC's ability to maintain a reliable system, which ultimately affect DESC's customers. Given that these QFs are not subject to the same reliability standards as DESC, they oftentimes may not engage in the proactive maintenance and investment required to avoid these operating issues, and the Commission finds it appropriate to grant DESC this mechanism in the Form PPA and Standard Offer by which it can require the QF to address the resulting operating issues. Importantly, DESC does not intend to prescribe precisely how such issues are remedied and provides the QF 8 months to do so. The Commission finds that this strikes a reasonable balance and may encourage QFs to

[13] DESC Witness Folsom noted that although this language is not in the current form contracts, DESC recently negotiated and executed a PPA that contains identical language as proposed in this docket.

proactively address these issues—as they should have done all along. No parties expressed disagreement with these proposed changes, and the Commission approves the same.

e. ATTACHMENT D – Insurance Requirements.

DESC Witness Folsom presented DESC's proposed changes to the insurance requirements in the Form PPA and the Standard Offer. The primary changes to ATTACHMENT D – Insurance Requirements result in:

a. DESC being able to request a certificate of insurance at any time during the term, which the QF must then furnish within 20 days;

b. Increase in the amount of General Liability insurance coverage to $2,000,000 per occurrence and $4,000,000 in the aggregate;

c. Increase in the amount of Employer's liability insurance coverage to $2,000,000 for each accident for bodily injury or for each employee for bodily injury by disease;

d. Increase in the amount of Environmental Impairment insurance coverage to $2,000,000; and

e. Addition of Comprehensive Automobile Liability insurance coverage of at least $2,000,000.

DESC Witness Folsom explained that the modifications to this exhibit conform with Dominion Energy, Inc.'s requirements for insurance. *Dominion Energy South Carolina, Inc., Amended Application to Approve and Establish the Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and all other Appropriate Terms and Conditions*, Ex. 6, Attach. D, Docket 2021-88-E (filed June 7, 2021). In response, CCEBA Witness Levitas expressed disagreement over both the "(1) new timing for certificate of insurance delivery, and (2) revised coverage amounts." 5 Tr. at 216.9. As for the timing of certificate delivery, he argued that it would give "DESC unfettered discretion to require proof of insurance at any time after a PPA is signed." *Id*. As such, CCEBA Witness Levitas maintained that this change would "impose unnecessary costs and burdens on QFs." 5 Tr. at 216.10.[14] DESC Witness Folsom responded that this change simply reflects the underlying obligations of the PPA and maintaining insurance is a basic aspect of "developing such a complex and costly facility." 3 Tr. at 197.34. As a result, CCEBA Witness Levitas noted that he found Witness Folsom's testimony "persuasive" and withdrew his objection to that change. 5 Tr. at 206.24. No other party expressed disagreement with this proposed change.

As for the proposed increases in coverage amounts, CCEBA Witness Levitas simply described them as "arbitrary," with the net effect of "needlessly discriminating against independent power producers." 5 Tr. at 218.8. In response, DESC Witness Folsom noted that CCEBA and DESC appear to agree with the types of coverage required, and only disagree upon the amounts of such coverage. 3 Tr. at 197.5. Witness Folsom noted that these increased amounts not only conform to DESC's parent company, but they also reflect the use of emerging technologies in the industry, which typically increase the insurable value of these projects, while also introducing additional safety concerns. *Id*. Moreover, Witness Folsom explained that the cost to construct these projects would be sufficient justification for raising these insurance limits, given that those costs could amount to "something closer to 80 or 90 million." 3 Tr. at 231.5-231.6. CCEBA Witness Levitas acknowledged that the addition of certain emerging technologies increases the value of these QFs, but argued that this alone is not sufficient justification to adopt the increased coverage amounts proposed by DESC. 5 Tr. at 218.7.

As for LEI, it recognized that "the proposed coverage levels are generally obtainable in the marketplace." LEI Report at 64. Finding the middle-ground between CCEBA and DESC, LEI

[14] The Commission notes that the Form PPA and Standard Offer require these QFs to maintain insurance throughout the term of the agreement.

recommended that the Commission adopt DESC's increased coverage amounts only for the Form PPA, while maintaining existing coverage amounts for the Standard Offer. 7 Tr. at 44.3. LEI provided three examples of coverage limits required by other utilities, which—according to LEI—support its recommendation to stagger the insurance coverages, with the increased amounts applying to the larger facilities under the Form PPA. LEI Report at 64.

DESC Witness Folsom highlighted the common-ground between DESC and LEI on this point given that LEI also recommended that the Commission increase the coverage amounts in the Form PPA. 8 Tr. at 129. He explained that these increased coverage amounts "mitigate the risk for DESC's customers, particularly given that [emerging technologies] can present increased costs and potential safety concerns." 8 Tr. at 131.3.

The Commission finds that the proposed changes to the insurance provisions in both the Form PPA and Standard Offer—as proposed by DESC—are approved as reasonable customer protection measures. As explained in detail throughout the record and this order, development of these QF generators is becoming more costly and more complex. Requiring increased insurance on these projects in response to these development trends should not be controversial. The Commission does not believe that QFs would incur a material expense in obtaining such insurance coverage—particularly given that the costs to construct these projects can approach $100,000,000. The Commission finds testimony relating to DESC's parent company persuasive given that these amounts have been used in the marketplace. Furthermore, the existing coverage amounts have remained the same for at least four years given that they were not modified in DESC's prior avoided cost hearing. Additionally, the Commission finds no compelling reason to deviate from past practice and maintain different coverage levels in the Form PPA than in the Standard Offer. Fundamentally, these protections exist to protect DESC's customers, and the Commission finds that whatever impact would arise—under the Standard Offer or the Form PPA— to projects from these changes would be minimal. As such, the Commission approves DESC's proposed changes related to insurance in both the Standard Offer and Form PPA.

f. ATTACHMENT F – Form of Surety Bond.

DESC Witness Folsom also sponsored revisions to the surety bond utilized in conjunction with the Form PPA and Standard Offer, which conform with Dominion Energy, Inc.'s form for such a bond. 3 Tr. at 190.23. CCEBA Witness Levitas argued that the surety bond should be rejected in its entirety, but only pointed to two discrete items that he deemed "particularly unreasonable." 5 Tr. at 216.11. First, he expressed concern over the shortened time during which the surety must make payment under the new form—which shortens the time from 15 days to 10 days. *Id*. Citing his "experience," he alleged that surety providers "are often unwilling to execute surety bonds containing such a short payment period." *Id*. Next, Witness Levitas objected to the new forms' requirement that the surety waive certain defenses to payment. *Id*. He further described this provision as a "poison pill that will very likely dissuade any surety from issuing a bond in favor of a QF." 5 Tr. at 216.12.

However, both DESC and LEI reported experience to the contrary. For example, DESC Witness Folsom noted that DESC's parent company "has utilized this from surety bond in the marketplace for a number of years." 3 Tr. at 194.8-194.9. Witness Folsom provided important context for these changes, noting that if DESC is forced to draw upon a surety bond, "you've probably reached some sort of a very severe situation in terms of the status of the PPA, even to the point of the seller being in default." 8 Tr. 135.17-135.20. LEI noted similar experience as DESC and explained that "based on [its] previous experience obtaining surety bonds, [LEI] does not believe the proposed changes would make surety bonds more difficult to obtain in the marketplace." LEI Report at 66. As such, LEI recommended that the Commission adopt DESC's proposed form of surety bond. *Id*.

The Commission finds that these changes appropriately mitigate risks to consumers without unduly burdening QF development. This is evidenced by LEI's and Dominion Energy's experience in the marketplace, which indicates that surety can, and is, obtained using this form. As the Commission explained above, performance assurance in these contracts is a fundamental customer protection. It serves as a safety net for DESC and its customers if a QF does not live up to the agreed-upon obligations in the contract. Shortening the payment window by only 5 days and removing a barrier to collection—collection that is properly due to DESC—are changes whose benefits to customers outweigh the impacts, if any, to QF developers. Furthermore, these changes must be taken in context. For example, if DESC is attempting to collect on a surety bond, that very likely means that the QF counterpart is illiquid, or at the very least, unwilling to fulfill its agreed-upon obligations. Without appropriate mechanisms for recovery, DESC's customers remain exposed to these risks. Likewise, neither the Form PPA nor the Standard Offer mandate that QFs utilize the surety bond option. The surety bond is one of a number of options that the QF can utilize at its discretion—however, all such options must adequately protect DESC's customers. The Commission finds that these changes provide such protection and are approved.

g. Other Modifications.

In addition to the modifications outlined above, other minor administrative and/or "clean-up" edits were incorporated into (i) the opening paragraph, (ii) the definition of Emergency Condition, (iii) Section 4.3(b) (Form PPA only), (iv) Section 11.10, and (v) Section 15.2. 3 Tr. at 190.23. No party expressed disagreement with these proposed changes.

Although DESC proposed no other changes to the Standard Offer and Form PPA in this docket, CCEBA Witness Levitas raised a new topic on rebuttal related to ancillary services. 5 Tr. at 216.13. Witness Levitas explained that "ancillary services include services necessary to maintain the integrity of the transmission system during a transaction, such as reactive supply and voltage control from generation." 5 Tr. at 216.12. He testified that DESC's Form PPA and Standard Offer include an express reference to "ancillary services" within the definition of "Energy." 5 Tr. at 216.13. According to Witness Levitas, this definition means that DESC should adjust the avoided cost rates paid to QFs to reflect the value of the ancillary services provided under these contracts. *Id*.

However, DESC Witness Kassis explained that ancillary services are not included in the calculation of avoided costs because QFs do not provide ancillary services to DESC. 1 Tr. 27.11 He noted that for DESC to compensate these QFs for ancillary services through avoided costs, they must have the "ability to provide additional services that [DESC] would normally provide," such that DESC can truly avoid the costs it would otherwise incur in providing these services. *Id*. Witness Kassis explained that these QFs currently do not provide any ancillary services and that once a QF proves it is capable of doing so, the costs avoided by DESC will be calculated on a case-by-case basis—which is consistent with DESC's PR – Avoided Costs Methodology tariff. 1 Tr. at 27.12. As an example, Witness Kassis specifically pointed to Reactive Power capability, which is an ancillary service. 1 Tr. at 27.13. Witness Kassis noted that Reactive Power is included in both the IA and Form PPA because a determination of what a QF can provide is made on a case-by-case basis and the value of those services may vary based upon whether they are provided to the Transmission Provider or purchasing entity—which in some cases may be unaffiliated. *Id*. He explained that covering this specific ancillary service in both documents is appropriate and is just one example of how DESC would be willing to negotiate ancillary services on a case-by-case basis. *Id*. However, given that no QFs provide ancillary services to DESC, Witness Kassis maintained that including a value for such services in the Avoided Cost Methodology would be inappropriate. *Id*.

CCEBA Witness Levitas claimed that Witness Kassis's testimony introduces confusion given that the Form PPA and Standard Offer expressly reference ancillary services, but QFs are not compensated for those services because they do not provide them. 5 Tr. at 218.12. As for Witness Kassis's testimony that any such ancillary services would be negotiated on a case-by-case basis, Witness Levitas alleged that the Commission should force DESC to "adopt a transparent, commercially reasonable, Commission-approved process for making such determinations." 5 Tr. at 218.13. Witness Levitas further argued that, contrary to Witness Kassis's testimony, the Commission should ensure that reactive power is addressed in the IA or Form PPA, but not both. *Id*.

However, at hearing, Witness Folsom testified that DESC is "willing to look at making adjustments to the definition of energy in the PPAs" on this point, in-line with Witness Levitas's recommendation. 3 Tr. at 222.15-222.17. Witness Folsom noted that DESC would be willing to modify this language to ensure that any such payment for ancillary services arises only after "a very clearly studied and well-defined demonstration that a QF is providing such services." 3 Tr. at 223.15-223.17.

The Commission finds Witness Folsom's compromise on this point a reasonable one, but declines CCEBA Witness Levitas's recommendation to address reactive power in only the IA or the PPA. As for ancillary services under the Form PPA and Standard Offer, the record is clear that ancillary services are not accounted for in avoided costs because solar QF generators are not currently providing any ancillary services that would permit DESC to avoid any related costs. As such—in line with DESC Witness Folsom's testimony—the Commission finds that the default position under the Form PPA and Standard Offer is that QFs do not provide ancillary services. Only after demonstrating that a QF can provide these services in a manner that permits DESC to avoid related costs should DESC be required to pay for the same. The Commission does not find the need to adopt some sort of process for this demonstration and corresponding payment, as suggested by Witness Levitas, given that these avoided costs would be calculated just like any other avoided cost pursuant to DESC's methodology. On this point, the Commission orders DESC to file a compliance Form PPA and Standard Offer contract with modifications reflecting this decision. As for Witness Levitas's recommendation to address reactive power in only the IA or Form PPA, rather than both, the Commission does not find a compelling reason to do so. In fact, the Commission recognizes that there may be times when the purchaser and Transmission Operator may be different entities with different needs related to reactive power. Restricting reactive power to one document or the other would unnecessarily hamstring these entities and cut off potential value streams for QFs that have the flexibility to provide value via reactive power to both the Transmission Operator and the purchasing entity.

2. Notice of Commitment to Sell Form

DESC Witness Folsom provided the background of the Notice of Commitment to Sell Form, which is a creature of Act No. 62. 3 Tr. at 190.7. Specifically, Act No. 62 requires that a QF "shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed [NOC Form]." *Id*. Witness Folsom explained that, practically speaking, this means that a QF can lock-in avoided cost rates—without executing a PPA or Standard Offer—simply by delivering the NOC

Form to DESC. *Id*. Although PURPA does not require states to implement NOC Forms, Witness Folsom described a parallel concept under PURPA that is embodied by the NOC Form—a LEO. *Id*. Witness Folsom opined that the LEO concepts under PURPA are instructive when framing the NOC Form under Act No. 62 given that the act is simply a part of this State's implementation of PURPA. 3 Tr. at 190.8.

In looking to these LEO concepts under PURPA and how other states have implemented the same, DESC Witness Folsom noted that it is clear the primary purpose of a LEO is to provide a QF with an avenue to move forward with project development when a utility simply refuses to negotiate a PPA. *Id*. Witness Folsom explained that the FERC most recently addressed the LEO concept in Order No. 872, and re-affirmed that the states have wide discretion to establish the parameters of a LEO, but at the very least, a QF must demonstrate "commercial viability" and a "financial commitment" to construct the proposed project pursuant to objective, reasonable, state-determined criteria." 3 Tr. at 190.12. Witness Folsom stated that although states maintain discretion in implementing the LEO framework, state LEO standards time and again reflect the same underlying principle—that in exchange for this non-contractual, yet binding, LEO framework, a QF must make a "substantial commitment" to sell the electrical output of its facility as a condition to establishing a LEO. 3 Tr. at 190.11. This is important because, according to Witness Folsom, "you have to be at some reasonable level of maturity in your project to even be able to fulfill the obligations under the NOC form." 8 Tr. 141.7-141.9. As such, Witness Folsom provided background on how the existing NOC Form is structured to evidence a "substantial commitment" on the part of the QF—including requiring certifications regarding delivery term, site control, and permitting. 3 Tr. at 190.11. CCEBA Witness Levitas also acknowledged that QFs must evidence a heightened level of commitment prior to establishing a LEO, which Witness

Levitas noted could be formed by the QFs "**unequivocally** committing to sell their output to the utility." 5 Tr. at 216.7. (emphasis added).

As for the changes proposed in this docket, DESC Witness Folsom characterized the changes as revolving around three primary tenets: (i) energy storage, (ii) site control, and (iii) termination. 3 Tr. at 190.12.

a. Energy Storage.

DESC Witness Kassis explained that these changes are part of a larger effort by DESC to evaluate "how emerging technologies can be utilized within the DESC [system] to provide value to its customers." 1 Tr. at 20.41.[15] As for the specific changes to the NOC Form related to energy storage, DESC Witness Folsom explained that they are intended to accommodate a wider range of projects, while at the same time ensuring that DESC obtains enough information about those projects to calculate accurate avoided costs under the NOC Form. 3 Tr. at 190.13. DESC Witness Kassis explained that not only does DESC seek to accommodate QF storage projects through the revisions to the NOC Form, but it is also continuously evaluating whether DESC-owned storage can be deployed to provide benefit to its customers. 1 Tr. at 20.41.

The Commission notes that no parties disputed these changes to the NOC Form, and these changes appear to strike an appropriate balance. On one hand, these changes do not present an undue burden to QFs because the revisions simply request information that a project able to make a "substantial commitment" should have on-hand. This fact alone, in and of itself, is helpful to prevent speculative projects from obtaining LEOs, in line with FERC's guidance. On the other

[15] DESC Witness Kassis also provided the Commission with testimony regarding enhanced benefits that a DESC-owned energy storage asset could provide over a similar asset that would be subject to PURPA's fuel and usage limitations.

hand, the changes represent an effort on the part of DESC to accommodate a broad array of projects under the NOC Form. As such, the Commission approves these changes.

b. Site Control.

As discussed above, the FERC's recent reform efforts via Order No. 872 touched upon a wide array of topics under PURPA—including implementation of the LEO concept at the state level. As explained by DESC Witness Folsom, although the FERC re-iterated that states have wide discretion in implementing the LEO framework, the FERC placed certain parameters around that authority. 3 Tr. at 190.14. One such parameter identified by Witness Folsom relates to site control and was the primary driver in DESC's revision related to the same. *Id*. Specifically, although the FERC held that it is reasonable to require the QF to take all steps within its power to establish site control, "it should not be punished for delay or inaction on the part of others." 3 Tr. at 190.14. Witness Folsom explained that DESC's revision to the NOC Form ensure that the QF has taken "meaningful steps" to commence construction and has "submitted all applications and filing fees necessary to operate and maintain the project." 3 Tr. at 190.14.

Although CCEBA Witness Levitas noted that he had "no problem with site control being a prerequisite to LEO formation," and testified that the NOC Form should not reference commencement of construction. 5 Tr. at 216.16. Witness Levitas stated that construction is "not germane to formation of a LEO." *Id*. Witness Levitas further protested these changes to the NOC Form by noting that QFs must first be able to "secure financing for the project" before the project is able to apply for relevant permits, such as stormwater and construction permits. 5 Tr. at 216.17. In response, DESC Witness Folsom noted that the changes to the NOC Form related to site control were simply intended to reflect the principles in Order No. 872. 3 Tr. at 197.9. Witness Folsom provided further modifications to the site control language related to commencement of construction to "clear up any confusion . . . [and] more closely resemble the FERC's order." *Id*. As for the permitting requirement within the NOC Form, Witness Folsom again highlighted that the proposed changes came directly from Order No. 872. *Id*. Notwithstanding this fact, Witness Folsom explained that DESC believes it has adequate permitting protections in place under the PPA and that it can modify the NOC Form to refer to only those permits required prior to commencement of construction. 3 Tr. at 197.10. However, in presenting this compromise, Witness Folsom highlighted the need "to place a reasonable parameter on the amount of time a QF has to execute a PPA after submitting the NOC Form" to ensure that the permitting protections therein take effect in a timely manner, as proposed in DESC's changes to the NOC Form. *Id*. However, CCEBA Witness Levitas further protested these changes and noted that "[a]lthough FERC may have authorized a reference to commencement of construction, it does not require it." 5 Tr. at 218.9. Witness Levitas suggested that DESC simply require that the site be of "sufficient size" instead. *Id*. Witness Levitas also rejected DESC's proposed compromise on the permitting language within the NOC Form and argued that application for any such construction-related permits is "not a reasonable test of a QF developer's commitment to selling its output to the utility." 5 Tr. at 218.11. As such, Witness Levitas suggested that the Commission reject these changes in their entirety. *Id*.

Recognizing these proposed modifications as an un-resolved dispute between the parties, LEI suggested that the Commission maintain the "original language pertaining to site control" in DESC's existing, Commission-approved NOC Form. LEI Report at 68. In support of this recommendation, LEI explains that Duke's NOC Form has no similar requirement and:

> The original language regarding site control was approved in the 2019 avoided cost proceeding and strikes a reasonable balance between protecting customers by

> ensuring QFs demonstrate a sufficient commitment to seeing their project through to completion, while not subjecting QFs to unreasonably onerous requirements.
>
> *Id*.

Although LEI did not mention Order No. 872 in suggesting that the Commission reject DESC's proposed changes, DESC Witness Folsom explained that the existing, Commission-approved, NOC Form requires the QF to "actually obtain site control prior to locking-in rates under a LEO." 8 Tr. at 131.4. He explained that the FERC clarified that utilities can require that the QF must take certain actions within its control, regardless of whether it actually obtains site control. *Id*. DESC viewed these edits as best practices handed down from FERC, which noted that these best practices should actually "encourage development of QFs"—contrary to the testimony of CCEBA Witness Levitas. 5 Tr. at 131.4. Although LEI recommends that DESC maintain its existing language, Witness Folsom explained that both LEI and DESC apparently recognize the need for a QF to evidence a substantial commitment prior to establishing a LEO. *Id*. CCEBA Witness Levitas did not provide responsive testimony to the LEI Report.

The Commission finds that these changes, as proposed by DESC in its Application and as modified by DESC over the course of this proceeding, are approved. As made clear by DESC Witness Folsom, the FERC handed down very clear guidance on this issue in Order No. 872. The Commission's review of the record and Order No. 872 reveals that DESC's changes to the site control language in the NOC Form squarely reflect the FERC's guidance. Notwithstanding DESC's implementation of the FERC's guidance, the Commission finds it reasonable that a project making a "substantial commitment" to sell power to DESC would have necessarily applied for permits and advanced toward beginning construction. This seems like a common-sense approach to establishing, in part, a LEO. Eliminating these references would appear to perpetuate the very projects which the FERC intended to discourage via Order No. 872—speculative, nascent projects that cannot be reasonably described as committed to anything. The Commission finds CCEBA Witness Levitas' recommendation particularly troubling, given that simply having a plot of land "of sufficient size" provides no indication whatsoever of the QF's ability and desire to develop that plot of land and sell power from the same within one year of submitting the NOC Form. As for LEI, the Commission appreciates its review of this dispute between the parties, but the Commission believes the FERC's best practices handed down in Order No. 872 are appropriate for South Carolina.

c. Termination.

The final category of edits to the NOC Form proposed by DESC relate to termination of the NOC Form. 3 Tr. at 190.15. DESC Witness Folsom explained that the revised NOC Form does not punish the QF if the NOC Form is terminated due to the fault or delay of DESC. *Id*. However, if the QF terminates the NOC Form—meaning that it would not proceed to execute a PPA or sell power to DESC—then DESC "will not be obligated to offer that QF within the next two years higher rates than DESC's applicable avoided costs" at the time the QF submitted the NOC Form. *Id*. Witness Folsom characterized this revision as a consumer protection measure which prevents developers from submitting, terminating, and re-submitting NOC Forms to simply obtain higher rates. *Id*. Witness Folsom stated that this approach aligns with the FERC's desire to limit speculative projects and ensures that DESC's system planning—and thus, its customers—are not adversely impacted. *Id*. CCEBA Witness Levitas did not express disagreement over this change. Witness Levitas, however, suggested a revision to another termination provision within the NOC Form. 5 Tr. at 216.17. Specifically, he noted that Item 8(ii) within the NOC Form would essentially terminate the NOC Form if a QF does not execute a PPA within 90 days of submitting the NOC

Form. *Id*. Witness Levitas recommended that this provision be modified to say that the NOC Form only terminates if a QF does not execute a PPA within the later of (i) 90 business days of the submittal date or (ii) 60 business days after the receipt of an executable PPA from DESC. 5 Tr. at 216.18. DESC Witness Folsom responded by re-iterating the need to ensure these projects execute a PPA in a timely manner, particularly given the other concessions made by DESC related to the NOC Form. 3 Tr. at 197.10. However, he went on to explain that as projects become more complex, it is reasonable to suspect that projects may take longer to negotiate PPAs. *Id*. As such, DESC agreed to incorporate CCEBA Witness Levitas's change, which provides the QF the later of 90 business days from the submittal date or 60 business days of receipt of the PPA to execute the same. 3 Tr. at 197.101.

The Commission finds a continued need to ensure that QFs submitting the NOC Form progress steadily to development—one such indicator is the execution of a PPA. In this instance, the agreement reached by the parties adequately ensures such progression, while holding the QF harmless if the cause for delay is on the part of DESC. As for DESC's proposed edits that would prevent QFs from obtaining higher avoided cost rates within two years of terminating the NOC Form, the Commission finds that this mechanism is appropriate to further limit the possibility of speculative projects or potentially gaming rates. For example, without this prohibition, a project that is not substantially committed to development could repeatedly submit and terminate NOC Forms as a form of price discovery, only committing to develop a project after it obtains its desired rate. This runs contrary to the underlying purpose of the NOC Form, which requires the QF to first commit, and then obtain the appropriate avoided cost rates. These edits reflect that concept and mitigate the potential gaming of the NOC Form as a price-discovery mechanism. Therefore, the Commission approves these proposed changes.

3. Mitigation Protocols

As described above, much of the testimony in this proceeding revolved around the value of the VIC, which represents the costs incurred by DESC to integrate QF solar generators onto its system. However, DESC Witness Kassis provided testimony regarding a potential path for these QFs to mitigate the costs by complying with DESC's proposed Mitigation Protocols.[16] 1 Tr. at 20.40. At a high level, Witness Kassis explained that any solar QF desiring to reduce or eliminate the VIC must first "reduce or eliminate the need for DESC to carry additional operating reserves as a result of such QF's generation."[17] *Id*. Witness Kassis testified that to do this, QFs must smooth out their intermittent generation profile by reducing unplanned drops in generation. *Id*. As such, the Mitigation Protocols contain a Solar Site Variability Metric (the "SSVM"), which is calculated pursuant to a spreadsheet provided by DESC. 1 Tr. at 181.13-181.14. If the maximum SSVM for a specific generator over the course of a month is 25% or less, the generator pays no VIC. *Id*. If the SSVM is between 25% and 45%, the generator pays half, with anything over 45% resulting in no reduction of the VIC. *Id*.

CCEBA Witness Burgess argued that the Commission should not approve DESC's proposed Mitigation Protocols, and objected to the calculation of the SSVM, which is the mechanism via which the protocols measure variability of QF generation. 5 Tr. at 16.32. Witness Burgess opined that rather than comparing output to a prior hour's production, the SSVM should

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[16] These Mitigation Protocols were originally filed by DESC in Docket No. 2019-184-E and are currently pending before the Commission.

[17] The Commission ordered the imposition of an EIC and a VIC. The difference between the VIC and EIC is largely administrative, as both attempt to recover similar costs. The EIC is currently factored into DESC's avoided cost methodology, while the VIC is meant to collect such costs under certain existing power purchase agreements with rates that do not account for such costs. For ease of reference, this order only references the VIC, but the Mitigation Protocols would apply to both equally.

instead compare output to expected production to gauge variability. *Id*. Witness Burgess further took issue with the hours captured in the SSVM calculation. *Id*. As proposed, the SSVM captures the hours that have the potential for the greatest percentage drop in generator output, but Witness Burgess argued that the SSVM should instead capture the greatest potential MW drop—regardless of percentage. *Id*. CCEBA Witness Burgess declared that DESC should only view the average SSVM over the course of a month—rather than only the maximum—and that the SSVM should account for system-wide solar production rather than just one site. 5 Tr. at 16.33. CCEBA Witness Burgess continued to take issue with the "practical implementation" of the Mitigation Protocols and suggested that (i) separate meters not be required, (ii) QFs have five days after month's end to submit the SSVM calculation, rather than two, and (iii) QFs not be disqualified after failure to submit the calculation for any two months. 5 Tr. at 16.34. Although Witness Burgess conceded that the SSVM could be used as a starting point, he also recommended that the Commission reject the protocols in their entirety and simply adopt similar protocols utilized in North Carolina, subject to certain modifications proposed by Witness Burgess. 5 Tr. at 16.33.

In response, DESC Witness Bell noted that DESC could update the Mitigation Protocols, if requested by the Commission, to account for forecasts over each five-minute period calculated within the SSVM instead of the one-hour lookback. 1 Tr. at 181.13. Witness Bell explained that this change would also impose additional obligations onto these generators, such as entering forecasts for each five-minute period into the calculation. *Id*. Likewise, Witness Bell stated that not only would these forecasts have to be supplied by the QFs, but they also must meet some threshold accuracy level to even be considered in the Mitigation Protocols to prevent QFs from gaming the spreadsheet by presenting favorable, but inaccurate, forecasts. 1 Tr. at 181.14. As for the other edits proposed by CCEBA Witness Burgess, DESC Witness Bell noted that the

Mitigation Protocols already provide a level of tolerance for the scenarios described by Witness Burgess. *Id*. Specifically, Witness Bell explained that in order to completely eliminate the VIC applicable to a QF generator, that QF generator does not have to completely eliminate its variability—rather, it simply has to reduce the SSVM below 25%. *Id*. As for Witness Burgess's suggestion to judge variability from a range broader than each site, DESC Witness Bell noted that DESC could aggregate this information for facilities that "are under contract with DESC by the same owner." 1 Tr. at 181.16. However, that owner would have to provide "the aggregated generation meter data and aggregated forecast data in one properly completed SSVM spreadsheet each month." *Id*. As for Witness Burgess's recommendation to adopt certain protocols from North Carolina, Witness Bell explained that this would not alleviate the reserves required to be carried by DESC. 1 Tr. at 181.17. Specifically, those North Carolina protocols look at the "average volatility of variable generators" which is "not the improvement that will save costs when considering additional reserves." *Id*. As such, Witness Bell maintained that the Mitigation Protocols are appropriate because they focus on mitigating the largest drops in generation, which are the drops that have to be covered in real-time and therefore cause DESC to carry additional operating reserves. *Id*.

As for LEI, it reviewed the specific disputed items related to the Mitigation Protocols and noted that it "agrees with DESC's proposed mitigation protocol and SSVM calculation, so long as the modifications which Witness Bell noted in his rebuttal testimony are incorporated." LEI Report at 74. LEI noted that these changes include "calculating solar QF production variability relative to forecast rather than actual, as well as allowing solar owners to aggregate production data from across QFs they own." *Id*. LEI further confirmed that the production meter requirement is not "particularly onerous" and "far from a material issue." LEI Report at 59. LEI also rejected Witness

Burgess's recommendation that the deadline should be extended for submission of the SSVM spreadsheet, but did suggest that the Commission reject the "two-strike" disqualification provision under the Mitigation Protocols. *Id*.

The Commission finds that the Mitigation Protocols proposed in this docket, as modified via Witness Bell's testimony, provide QFs with reasonable opportunities to mitigate their variability and thereby reduce the VIC applicable to such generators. As discussed above, the Commission recognizes that the variability of these intermittent QF generators means that DESC incurs additional costs in the form of operating reserves. These operating reserves are necessary to ensure that DESC can maintain a reliable and balanced system for its customers. The record reveals that these additional reserves correlate to the large, unexpected drops in generation from these QFs. As such, the Mitigation Protocols appropriately align those drops with corresponding reductions in the VIC. Likewise, the Commission finds it appropriate to measure such drops utilizing a percentage mechanism rather than a pure MW measure. Importantly, the Mitigation Protocols already contain measures to address Witness Burgess's concerns related to this point, including limiting the SSVM measurement to daylight hours excluding drops less than 10% of nameplate capacity. As to Witness Burgess's suggestion to simply adopt certain protocols from North Carolina, this misses the mark given that the VIC and these protocols reflect the specific realities of the DESC and renewable generation landscape in South Carolina—things that are not accounted for in the North Carolina protocols. Additionally, the Commission recognizes that DESC made several concessions in this docket related to the protocols—including relying upon forecasts and aggregating certain sites. However, the Commission understands that potential exists for QFs to submit favorable, inaccurate forecasts to "game" the Mitigation Protocols. As such, the Commission approves the Mitigation Protocols as proposed by DESC, but orders DESC to evaluate what modifications may be required, if any, to ensure that QFs are incentivized to submit accurate forecasts.

4. DESC's Proposed Rate Schedules

DESC Witness Rooks sponsored the Company's proposed rate schedules and riders in this proceeding. Witness Rooks first sponsored DESC's proposed updates to Rate PR-1 to reflect the Company's proposed avoided costs for QFs that have power production capacity less than or equal to 100 kW. 4 Tr. at 28.3-28.4 & 33.1-33.2; Hr'g Ex. 7 (Corrected Revised AWR-1 & Corrected Revised AWR-2). The Company's Rate PR-1 sets forth separate avoided energy and capacity costs for both solar and non-solar qualifying small power producers. *Id.* at 28.4. Next, Witness Rooks sponsored a new rate schedule, identified as Rate PR-Avoided Cost Methodology, which sets forth the Company's proposed methodology to be used in computing the avoided energy and capacity costs associated with PPAs as provided under the provisions of S.C. Code Ann. § 58-41-20 and PURPA. *Id*. at 28.4-28.5; Hr'g Ex. 6 (AWR-3 & AWR-4). Witness Rooks also sponsored the new Rate PR-Standard Offer rate schedule. *Id*. at 28.5-28.6 & & 33.1-33.2; Hr'g Ex. 7 (Revised AWR-5 & Revised AWR-6). This rate schedule incorporates DESC's proposed Standard Offer, which is more fully described by DESC Witness Folsom and includes the Standard Offer avoided cost rates described and calculated by DESC Witness Neely. *Id.* Witness Rooks further sponsored the Company's Rate PR-Form PPA rate schedule, which includes DESC's proposed Form PPA as more fully discussed by Witness Folsom. *Id.* at 28.6-28.7; Hr'g Ex. 6 (AWR-7 & AWR-8).

As a general matter, several witnesses presented by the other parties of record proposed alternative avoided costs and methodologies through their testimony in this proceeding. These proposals, if approved by the Commission, consequently would require changes to the rate schedules sponsored by Witness Rooks. Based upon the stated findings of the Commission above, however, the Commission finds that DESC's proposed avoided costs and methodologies are appropriate and should be approved and, therefore, no changes to the rate schedules are necessary in these regards.

5. Transparency of DESC's Proposals

When asked whether DESC was reasonably transparent in this proceeding, ORS Witness Horii answered:

> Yes. The Company provided information in its filings and data responses that allowed me to assess the reasonableness of its proposals, to make important improvements to the assumptions, and follow those changes through the models so that I could derive my recommended tariffs and PPA rates.
>
> 6 Tr. at 32.4.

On the other hand, CCL/SACE Witness Sercy—who was hired just six weeks prior to the start of the hearing—stated that DESC's initial and amended applications, along with its direct testimony, omitted "several underlying inputs, assumptions and methodologies the Company used to develop its proposal." 4 Tr. at 60.33. Witness Sercy stated that DESC also failed to provide these key calculation inputs in response to discovery requests, forcing SACE and CCL to send "increasingly specific" discovery questions to get the information required to review DESC's proposal. 4 Tr. at 60.34. Witness Sercy asserted that DESC's failure to include this information in its filings hampered his ability to independently review and verify DESC's proposal. *Id*. Likewise, CCEBA Witness Burgess—who was also hired approximately six weeks prior to the hearing—stated that the DESC workpapers provided do not contain critical information on how Guidehouse calculated the incremental reserve requirements based on the solar volatility profiles. 5 Tr. at 16.18. Because of this, Witness Burgess stated that he has not been able to fully determine whether DESC's assumed solar volatility profile and related reserve requirements have been corrected. *Id*.

DESC Witness Neely stated that DESC's filing included the information needed to determine whether the pricing periods were reasonable. 5 Tr. at 16.18. Specifically, Witness Neely stated that DESC provided all the hourly marginal cost data as well as the hourly dispatch data for all modeling used to determine the hourly periods. 2 Tr. at 50.9. Witness Neely also explained that some of the "data requests were ask for before [DESC] even [had] the data." 2 Tr. at 143.10-143.11. As such, Witness Neely noted that for those requests, "there was no way that [DESC] could actually provide data" until it was actually created after those requests. 2 Tr. at 143.14-143.15. Witnesses Bell stated that DESC has provided intervenors several spreadsheets showing expected system marginal costs and containing over 87,000 hourly costs from each production run. 1 Tr. at 181.17. DESC Witness Kassis also rebutted Witness Sercy's allegations that DESC has not met the standard of transparency required by Act 62. 1 Tr. at 27.16. Witness Kassis stated that this allegation is not supported by the record and asserts that DESC has responded to over 90 discovery requests in this docket from the parties of record. *Id*. Moreover, Witness Kassis represented that with respect to SACE and CCL, DESC has responded to three separate sets of discovery. *Id*. Witness Kassis continued that each response was addressed openly and transparently, which is evidenced by the fact that neither SACE, CCL, nor any other party filed a motion to compel in this docket. 1 Tr. at 27.17. DESC Witness Bell stated that, contrary to Witness Burgess's suggestion, the Guidehouse study is extremely detailed and provides a full explanation of the methods used. 1 Tr. at 181.11.

As stated above, ORS Witness Horii stated that the DESC's filings in this docket were reasonably transparent for his independent review and analysis. 6 Tr. at 32.4. The LEI Report found DESC to be highly responsive to interrogatories but notes that this is only one part of being transparent. Hr'g Ex. 13 (LEI Report) at 70. The LEI Report stated that it posed nine interrogatories through three rounds of requests, and on average DESC responded within two days, which is well within the statutory 20 days allowed. Hr'g Ex. 13 (LEI Report) at 70. However, the LEI Report stated that transparency should be judged primarily not based on whether questions were answered when asked, but rather on whether the application was presented in a way which minimizes the need for interrogatories in the first place. Hr'g Ex. 13 (LEI Report) at 70. DESC Witness Kassis responded to the LEI Report by emphasizing his position that DESC has been transparent with all parties in this docket. 8 Tr. at 151.3. Witness Kassis added that DESC has clearly met, if not exceeded the applicable standard of transparency within Act 62. *Id*. Witness Kassis reiterates that all data requests were produced in this docket earlier than the applicable deadline. *Id*. Witness Kassis also stated that although LEI suggests that transparency should be judged by the need for interrogatories in the first place, this standard is not rooted in Act No. 62 and ignores the purpose of discovery. *Id*. Witness Kassis further stated that such a standard could lead to unintentional consequences and would prove impractical, which is evidenced by the fact that LEI failed to achieve its proposed standard.[18] *Id*.

The Commission finds that DESC well-exceeded the applicable standard of transparency in this proceeding, which is found within Act 62. Specifically, DESC provided hundreds of files to numerous intervenors, and several parties were able to replicate DESC's methodologies and calculations—including the ORS which testified that DESC in fact has achieved the applicable transparency standard within Act No. 62. Although certain parties may have desired for information to be provided along with the application rather than through subsequent discovery, this determination is one of reasonableness that will have to be decided on a case-by-case basis and does not lend itself to a concrete rule. To be clear, while applications should include some

[18] Several parties issued discovery requests to LEI, including DESC, CCEBA, and DCA.

basis of support, the discovery process is meant to address specific issues and in some cases address these issues in greater detail. If parties desire more information, they are certainly able to request the same. In this docket, it appears this process served its purpose—particularly given that no parties filed a Motion to Compel. As such, the Commission declines to adopt LEI's standard that transparency somehow be tied to the amount of interrogatories issued to a party. This would create perverse incentives for parties to simply lob interrogatories at other parties, and—even though all such requests may have been answered in full—point to such requests as evidence of a lack of transparency. The Commission declines to adopt any such standard. As such, the record reveals that parties could, and did, replicate DESC's calculations and apparently were able to obtain several hundreds of files through the discovery process related to DESC's filings. Therefore, the Commission finds that DESC met the "reasonably transparent" standard within Act No. 62.

VII. CONCLUSIONS OF LAW[19]

In entering its order in this proceeding, the Commission makes the following conclusions of law based upon the filings, testimony, and exhibits that were received into evidence at the hearing in this proceeding and based on the entire record of these proceedings:

1. The Commission has jurisdiction over this matter pursuant to Act No. 62 and S.C. Code Ann. § 58-41-20.

2. DESC is lawfully before the Commission pursuant to S.C. Code Ann. § 58-41-20 seeking approval of its calculations of avoided costs, its proposed avoided cost methodology, and its proposed Standard Offer, Form PPA, and NOC Form.

[19] To the extent the following conclusions of law are findings of fact, they are so adopted.

3. Act No. 62 requires the Commission to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage, both as part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals. The Commission also is required to ensure that the revenue recovery, cost allocation, and rate design of utilities that it regulates are just and reasonable and properly reflect changes in the industry as a whole, the benefits of customer renewable energy, energy efficiency, and demand response, as well as any utility or state specific impacts unique to South Carolina which are brought about by the consequences of Act No. 62.

4. The methodologies used by DESC to calculate its avoided energy and capacity costs under PURPA for its proposed Rate PR-1 and Rate PR-Standard Offer as described in the testimonies of Company Witnesses Neely and Bell are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; are just and reasonable; are nondiscriminatory to small power producers; and reduce the risk placed on the using and consuming public.

5. The avoided energy and capacity costs for DESC's proposed Rate PR-1 and Rate PR-Standard Offer, as shown in Tables 1-4 on pages 12-13 and Tables 5-8 on Pages 17-1818 of Company Witness Neely's Amended Direct Testimony, as modified on Pages 3-4 of his Rebuttal Testimony are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; are just and reasonable; are nondiscriminatory to small power producers; and reduce the risk placed on the using and consuming public.

6. With the modifications approved by the Commission herein, DESC's proposed Rate PR-1 and Rate PR-Standard Offer, including the rates, credits, charges, costs, underlying methodologies, and the related terms and conditions are lawful, just, and reasonable.

7. With the modifications approved by the Commission herein, DESC's proposed avoided cost methodology, as set forth in its Rate PR-Avoided Cost Methodology attached as Exhibit No. 6 (AWR-4) to the direct testimony of Company Witness Rooks, is reasonable and prudent; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is just and reasonable; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

8. With the modifications approved by the Commission herein, DESC's proposed Form PPA, as reflected in Rate PR-Form PPA attached as Exhibit No. 6(AWR-8) to the direct testimony of Company Witness Rooks, is just and reasonable; is commercially reasonable; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

9. With the modifications approved by the Commission herein, DESC's proposed NOC Form, as reflected in Revised Exhibit No. 5 (Revised JEF-1) to the rebuttal testimony of Company Witness Folsom is just and reasonable; provides small power producers a reasonable period of time from its submittal of the form to execute a PPA; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

10. Pursuant to Order No. 2020-244, the Company should be permitted to 1) true up variable integration costs for the period from the first billing cycle in May 2019 until the first

billing cycle for the month after the date of this order and 2) deduct these "trued up" costs from future payments made to the solar producers with existing PPAs containing the agreement in order to reimburse the Company for any such variable integration costs.

VIII. ORDERING PROVISIONS

IT IS THEREFORE ORDERED THAT:

1. The methodologies used by DESC to calculate its avoided energy and capacity costs under PURPA for its proposed Rate PR-1 and Rate PR-Standard Offer are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

2. The avoided energy and capacity costs for DESC's proposed Rate PR-1 listed in the table below are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Non Solar	P1	P2	P3	P4
	Non-Summer: Jan, Feb, Mar, Apr, Oct, Nov, and Dec		**Summer: May-Sep**	
$/kWH	5am-9am, 5pm-11pm	9am-5pm, 11pm-5am	2pm-11pm	11pm-2pm
May 2021 - April 2022	0.03435	0.02889	0.03338	0.02830

PR-1 RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	**($/kWh)**
December, January, February 6 am to 9 am	0.21781

PR-1 RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	**Year Round ($/kWh)**
May 2021-April 2022	0.02820

PR-1 RATE: AVOIDED CAPACITY COST
Solar QFs ($/kWh)

Time Period	**($/kWh)**
All solar generating hours	0.00140

3. The avoided energy and capacity costs for DESC's proposed Rate PR-Standard Offer listed in the table below are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

STANDARD OFFER RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11
	Dec, Jan, Feb				Mar, Apr, Oct, Nov				May- Sep		
$/kWH by 5 Year Period	5am-9am	9am-5pm	5pm-11pm	11pm-5am	5am-9am	9am-5pm	5pm-11pm	11pm-5am	11am-5pm	5pm-11pm	11pm-11am
2022-2026	0.03245	0.02599	0.03143	0.02801	0.02995	0.02580	0.03224	0.02693	0.02870	0.03260	0.02599
2027-2031	0.03651	0.02923	0.03535	0.03151	0.03369	0.02902	0.03627	0.03028	0.03228	0.03667	0.02923

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December, January, February 6 am to 9 am	0.21781

STANDARD OFFER RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

$/kWH by 5 Year period	All Hours
2022-2026	0.02695
2027-2031	0.02937

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Solar QFs ($/kWh)

Time Period	**($/kWh)**
All solar generating hours	0.00140

4. As modified by the Commission in this Order, Rate PR-1, Rate PR-Standard Offer, Rate PR-Avoided Cost Methodology, Rate PR-Form PPA, and the NOC Form, including the rates, credits, charges, costs, underlying methodologies, and the related terms and conditions are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

5. DESC is authorized to 1) true up variable integration costs for the period from the first billing cycle in May 2019 until the first billing cycle for the month after the date of this order and 2) deduct these "trued up" costs from future payments made to the solar producers with existing PPAs containing the agreement in order to reimburse the Company for any such variable integration costs.

6. Within ten (10) days of receipt of this Order, DESC shall file with the Commission and serve copies on the Parties the tariff sheets and rate schedules approved by this Order, which are as follows:

a. Rate PR-1;

b. Rate PR-Avoided Cost Methodology;

c. Rate PR-Standard Offer;

d. Rate PR-Form PPA

The avoided cost and other rates reflected in any such tariff sheets shall be consistent with the components and factors set forth herein. The revised tariffs should be electronically filed in a text searchable PDF format using the Commission's DMS System (https://dms.psc.sc.gov/). An additional copy should be sent via e-mail to etariff@psc.sc.gov to be included in the Commission's ETariff system (https://etariff.psc.sc.gov). DESC shall provide a reconciliation of each tariff rate change approved as a result of this order to each tariff rate revision filed in the ETariff system. Such reconciliation shall include an explanation of any differences and be submitted separately from the Company's ETariff filing. Each tariff sheet shall contain a reference to this Order and its effective date at the bottom of each page.

7. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

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Florence P. Belser, Vice Chair
(SEAL)

ATTEST:

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Jocelyn Boyd, Chief Clerk